IN THE COURT OF APPEAL OF THE STATE OF CALIFORNIA

FIRST APPELLATE DISTRICT

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Petitioner,

v.

CALIFORNIA PUBLIC UTILITIES COMMISSION

Respondent.

From Decision No. 23-06-029 (June 29, 2023) and Decision No. 23-12-038 (December 14, 2023) of the California Public Utilities Commission

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PETITIONER'S APPENDIX OF EXHIBITS IN SUPPORT OF PETITION FOR REVIEW

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CHRONOLOGICAL INDEX OF EXHIBITS

EXHIBIT	DOCUMENT	DOCUMENT DATE	PAGE RANGE
1.	D.05-12-041: Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters	12/16/2005	4–100
2.	Resolution E-4017, Approval of a Citation Program Authorizing Commission Staff to Enforce Compliance with System and Local Resource Adequacy Filing Requirements by Load-Serving Entities Within the Service Territories of California's Three Largest Investor-Owned Electric Utilities	10/5/2006	101–114
3.	Resolution E-4907, Registration Process for Community Choice Aggregators	02/09/2018	115–139
4.	D.23-06-029: Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements	7/5/2023	140–289
5.	California Community Choice Association's Application for Rehearing of Decision 23-06-029	7/26/2023	290–326
6.	D.23-12-038: Order Denying Rehearing of Decision 23-06-029 and Motion for Partial Stay	12/18/2023	327–361

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5.	California Community Choice Association's Application for Rehearing of Decision 23-06-029	7/26/2023	290–326
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EXHIBIT 1

D.05-12-041: Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters

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Decision 05-12-041 December 15, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB 117 Concerning Community Choice Aggregation.	Rulemaking 03-10-003 (Filed October 2, 2003)

(See Appendix A for List of Appearances.)

DECISION RESOLVING PHASE 2 ISSUES ON IMPLEMENTATION OF COMMUNITY CHOICE AGGREGATION PROGRAM AND RELATED MATTERS

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DECISION RESOLVING PHASE 2 ISSUES ON IMPLEMENTATION OF COMMUNITY CHOICE AGGREGATION PROGRAM AND RELATED MATTERS

This order resolves outstanding issues in Phase 2 of this proceeding, the purpose of which is to implement a program to permit purchases of power by Community Choice Aggregators (CCA) for local residents and businesses. This order is issued in compliance with Assembly Bill (AB) 117 (2002 Stats., ch. 838), enabling cities and counties to form CCAs.

I. Summary and Background

CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. The state Legislature has expressed the state's policy to permit and promote CCAs by enacting AB 117.[1] AB 117 authorizes the creation of CCAs, describes essential CCA program elements, requires the state's utilities to provide certain services to CCAs, and establishes methods to protect existing utility customers from liabilities that they might otherwise incur when a portion of the utility's customers transfer their energy services to a CCA.

Cities and counties have become increasingly involved in implementing energy efficiency programs, advocating for their communities in power plant and transmission line siting cases, and developing distributed generation and renewable resource energy supplies. The CCA program takes these efforts one step further by enabling communities to purchase power on behalf of the community. Already, several cities and counties have either formed CCAs or have stated an intent to create them.[2]

[1] Pub. Util. Code §§ 218.3, 331.1, 366.2, 381.1, and 394.25.

[2] AB 117 refers to "CCAs" as the legal entities that are the subjects of its provisions. For some reason, the utilities have referred to CCAs as "CCA Providers." Because that term

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Today's decision is the second decision issued in this proceeding to address ways to create a CCA program in compliance with AB 117. The Commission issued Decision (D.) 04-12-046 in Phase 1 of this proceeding that addressed rates and certain tariff and cost allocation issues. That order stated our intent to protect bundled utility customers from the possible cost impacts of CCA programs while seeking to establish reasonable costs for the utility services CCAs and their customers would require. AB 117 confers general jurisdiction over CCA program implementation, but requires the Commission to take certain actions to protect utility bundled customers and assure reasonable service to CCAs, actions that are incidental to our regulatory oversight of public utilities. The Commission has the authority to assert limited jurisdiction over certain CCA matters, including resource adequacy requirements, as discussed below.

Phase II considers the following broad issues:

1. **Commission jurisdiction over CCAs and CCA programs. "Vintaging" the Cost Responsibility Surcharge (CRS).** We establish a way to calculate the CRS for each generation of CCA in a way that recovers costs incurred on behalf of the CCA's customers but not more, also known as "vintaging." We adopt a calculation for each vintage of the CRS that is not controversial and do not permit the utilities to restrict a CCA's option to phase-in service to customer groups;

2. **The CCA's notification to the utility of its intent to serve customers**. We adopt an "open season" and discuss other ways of notifying the utility of the CCA's intent to purchase power for local customers and committing to relieving the utility and its remaining ratepayers of liability for power costs. Generally, we find that CCAs must make a binding commitment to be assured that the utility will stop purchasing power on behalf of its customers, that the utility

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has no relevance to the statute and is not defined either by the utilities or the statute, we do not use it here and it may not be used in tariffs.

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may not transfer its liability for load forecasting to the CCA and that we expect the utilities to work cooperatively with CCAs to minimize stranded power purchase liabilities. We also establish a collaborative process for refining departing load forecasts;

3. **The regulatory process for considering CCA implementation plans and registration.** Generally, we find that AB 117 does not provide us with authority to approve or reject a CCA's implementation plan or to decertify a CCA but to assure that the CCA's plans and program elements are consistent with utility tariffs and consistent with Commission rules designed to protect customers. We adopt a simple procedure for the filing of an implementation plan and a method of facilitating disputes between the utility and a CCA;

4. **Customer protections.** We adopt various customer protections, including how to treat service termination, partial payments and deposits, and customer notifications;

5. **Implementation rules and utility services to CCAs.** We adopt policies and rules for customer enrollment, scheduling coordination, call center operations, boundary meters, and customer switching,

6. **Service fees for utility services to CCAs**. We adopt utility charges and fees for such activities as opt-out processing, customer transfers of service, billing services, customer contacts, data processing and management, and confirmation letters to customers. Consistent with our order in Phase 1 of this proceeding, we adopt cost-based rates for services that impose costs on utilities that would not otherwise occur and which are not otherwise being recovered;

7. **Ratemaking for the CARE program.** We find that CCA customers should continue to receive the benefits of the CARE program and establish accounting for these subsidies;

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8. **Application of Renewable Portfolio Standard (RPS).** We find that the Commission should decide in Rulemaking (R.) 04-04-026 how to apply the RPS to CCAs.

Attachment A summarizes this order in more detail. Attachment C is a copy of relevant portions of AB 117.

This decision permits the complete implementation of the CCA program in California. We also state our commitment to refining the rules for the program as we gain experience with it.

II. Procedural Background

The Commission opened this rulemaking on April 27, 2003 to implement certain provisions of AB 117 (Chapter 838, September 24, 2002), which added Pub. Util. Code §§ 218.3, 331.1, 366.2, 381.1, and 394.25 and permits local governments the opportunity to aggregate energy procurement on behalf of the citizens and businesses in their communities.

AB 117 involves Commission-jurisdictional utilities by requiring them to continue to provide distribution, metering and billing services to the CCA's energy customers, among other things. AB 117 also directs the Commission to ensure that the utilities are able to recover certain costs, including those associated with energy contracts signed by the state's Department of Water Resources (DWR) and the costs of providing ongoing services to CCAs and their customers. This rulemaking stated our intent to implement fully the requirements of AB 117 that pertain to CCAs.

Following a prehearing conference on November 26, 2003, and with the agreement of all active parties, the Commission bifurcated the proceeding so that the Commission would first consider issues relating to certain utility costs that would be assumed by CCAs and later consider issues more concerned with transactions between CCAs, utilities, and energy customers. The Commission

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issued its first order, D.04-12-046, in December, 2004 resolving a variety of cost and rate issues. It subsequently held a second prehearing conference on March 30, 2005 and then evidentiary hearings in May 2005. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E) (together "Utilities") filed briefs jointly. The City and County of San Francisco (CCSF), the City of Moreno Valley, Community Environmental Council, the Local Government Commission, the County of Los Angeles and the City of Chula Vista (LA/CV) filed joint briefs and refer to themselves as "CCA Community and Supporters" (CCAs). Other parties that actively participated and filed briefs are the Office of Ratepayer Advocates (ORA), Community Environmental Council, Local Power, Toward Utility Rate Normalization (TURN), Energy Choice, Inc. (ECI).and the King's River Conservation District (KRCD). The California DWR consulted with the Commission on matters related to the delivery of "in-kind" power. Phase 2 of this proceeding was submitted on August 1, 2005 when reply briefs were filed.

III. Commission Jurisdiction over CCAs and the CCA Program

AB 117 establishes a program that permits cities and counties to create organizations called CCAs to provide certain utility services to local residents and businesses. The statute by necessity requires CCAs to rely on regulated electric utilities for a variety of services, such as metering and billing. This ongoing relationship between the CCA and the utility is essential partly because the utility retains the obligation to provide the CCA's energy customers with distribution and transmission services. The statute also specifies other obligations of the serving utility, such as offering customer notification services and customer information to the CCA. AB 117 directs this Commission to develop the rules, rates and policies that are required for the implementation of a

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successful CCA program, and also to oversee certain aspects of it on a continuing basis. The statute also directs CCAs to submit certain documents and information to the Commission, among other things.

In the process of developing the CCA program in this proceeding, the question has arisen as to whether and the extent to which AB 117 grants this Commission jurisdiction over CCAs and, by implication, the cities and counties that create and oversee them. Indeed, almost every controversy in Phase 2 of this proceeding somehow implicates the extent to which the Commission may or should control CCA activities, whether by way of utility tariffs or independently.

As part of the debate over Commission jurisdiction, the Utilities discuss the many and sometimes complex inter-relationships they will have with CCAs and speculate on some of the consequences of those relationships. For example, they observe that the CCA has no obligation to serve its customers and may abandon its energy service at any time. Utilities argue AB 117 intended for the Commission to have broad authority over CCAs and did not limit the scope of the Commission's authority in this regard. As evidence of this legislative intent, the Utilities cite several sections of the statute that refer explicitly to the Commission:

1. The CCA must file an implementation plan and a statement of intent with the Commission;
2. The CCA must register with the Commission; and
3. The Commission must adopt rules for CCAs before CCAs may offer services.

The Utilities argue that the Commission has exercised authority over Energy Service Providers (ESPs) and utility holding companies and that this "derived authority" extends equally to CCAs.

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ORA believes the Commission has "plenary" or "general" jurisdiction over public utilities only and that the Courts have distinguished between broad regulatory oversight on the one hand and more limited authority on the other. ORA observes that portions of AB 117 provide the Commission with certain authority over CCAs and believes that the Commission need not speculate further about the Legislature's intent.

CCAs reply that the Commission's role is primarily to "advise and assist" CCAs, which are entities of local government subject to open meeting laws and established procedures for public participation and information disclosure. As evidence that the Legislature did not intend for the Commission to assume jurisdiction over CCAs, CCAs observe that AB 117 requires an implementation plan in order to develop a cost responsibility surcharge (CRS) and that AB 117 does not require a CCA to submit changes to its implementation plan to the Commission. With regard to authority over CCAs, AB 117, according to CCAs, establishes responsibilities for the Commission that are primarily ministerial, for example requirements to notify the utility of a filed implementation plan, requesting additional information about the plan and requiring the CCA to register with the Commission.

The CEC, TURN and King's River generally share the CCAs' views on the authority AB 117 confers on the Commission over CCAs.

Discussion. In considering this Commission's jurisdiction over CCAs and the implementation of CCA program, we rely almost exclusively on the guidance provided by AB 117, which is the only California statute that guides the development of a CCA program.[3] Our review of AB 117 leads us to the general

[3] Other statues and our own decisions have addressed other areas of jurisdiction over CCAs and ESPs, for example, but not limited to the issue of resource adequacy requirements. (See e.g., D.05-10-042 and AB 380 (Ch. 367, Stats 2005) which, other

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conclusion that our authority over CCAs is circumscribed. AB 117's provisions are generally either permissive with respect to CCAs or direct us to regulate the utilities that serve them. That is, we interpret AB 117's requirements for the CCA to file an implementation plan, to register with the Commission, and to comply with program rules to be conditions of receiving related utility services. Just as a residential customer may have to submit a deposit as a condition of utility service or an industrial customer may have to install a meter to receive utility service, CCAs must take certain steps to receive the utility services they will require to provide power to their customers. The conditions of service imposed on utility customers do not confer upon this Commission general jurisdiction over customers. In the case of CCAs, the rules and procedures AB 117 requires are for the purpose of assuring the availability of adequate information for the utility to provide service and for the Commission to satisfy itself that the CCAs plans will not compromise the utility's ability to provide services to CCA customers and utility bundled customers.

The Commission must adopt rules *for the utility* in order that it may provide adequate service to the CCA and its customers while simultaneously protecting utility bundled customers and the utility's system. Nothing in the statute directs the Commission to regulate the CCA's program except to the extent that its program elements may affect utility operations and the rates and services to other customers. For example, the statute does not require the Commission to set CCA rates or regulate the quality of its services. To the contrary, while providing very precise guidelines on a number of issues involving the utilities' services to CCAs and ways to protect utility customers,

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things added Section 380 to the Pub. Util. Code and requires the Commission to consult with the ISO to establish resource adequacy requirements for all load-serving entities.

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the statute does not refer to how the Commission might oversee the rates and services CCA's offer to their customers.

In support of their view that the Commission has broad and general jurisdiction over CCAs, utilities cite D.04-07-037 which found that the Commission has authority over ESPs as a result of statutory language authorizing the Commission to suspend or revoke an ESPs's registration if an ESP were not financial capable of providing electric service. In the case of ESPs, the Commission has express statutory authority which AB 117 does not confer with regard to the CCA implementation program. In fact, the distinction is significant in that we must assume the Legislature would have explicitly granted us authority over these programs as it has in the case of ESPs if that is what it had intended. Instead, Section 394, which outlines how the Commission is to process ESP applications, explicitly exempts public agencies from its provisions.[4] However, the Commission has the authority to exercise limited jurisdiction over non-utilities in furtherance of their regulation of public utilities (*See PG&E Corp. v. CPUC,* 118 Cal. App. 4th (2001) 1195-1201).

The utilities also analogize to our authority over utility holding companies, but such references are without merit. Our authority over holding companies derives from our authority over their regulated utility subsidiaries. No such circumstance or law exists with regard to the implementation of CCA programs.

We are confident that existing law protects CCA customers. Entities of local government, such as CCAs, are subject to numerous laws that will have the effect of protecting CCA customers and promoting accountability by CCAs.

[4] Division 4.9 of the Public Utilities Code does address publicly-owned utilities, as does Section 9620, which specifically provides for resource adequacy requirements.

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Under existing law, a CCA must conduct public hearings, operate within a budget and disclose most types of information to members of the public. To the extent that a CCA fails to consider the interests of its customers - who are local citizens - there is recourse in subsequent elections, the courts and before local government agencies. We are not convinced that our oversight would necessarily contribute anything in that regard, as long as utility tariffs provide adequate protections for the integrity of the utility system and bundled ratepayers are protected from costs that are attributable to CCA customers, as AB 117 requires.

Although we find that we do not have broad regulatory authority over CCA program implementation, we do have authority to subpoena information and witnesses, to require information from a CCA and to require its involvement in any relevant Commission inquiry, authority we have over any individual or entity whose acts or knowledge are germane to our regulatory obligations. As the utilities argue, we also retain a responsibility to assure that a CCA's policies, practices and operations do not compromise the operations of the utility or services to utility customers. We may affect those protections in the CCA program rules that will be incorporated into utility tariffs. At this time, we have no reason to believe that this approach is inadequate to protect utility customers.

Finally, we address the utilities' complaint that they "should not be forced to adopt the tariff changes drafted by the local governmental agencies" and that they, the utilities, "are the entities responsible for writing and administering their own tariffs." We remind the utilities that every party to our proceedings is entitled to comment on utility tariff proposals and to our full consideration of their views. Local governmental agencies participating in this proceeding have done nothing novel by objecting to utility tariff proposals and proposing their

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own. More importantly, we most assuredly will order the utilities to modify their tariff language in ways they themselves did not propose if that tariff language is required to conform the tariffs with our view of the public interest, consistent with our statutory obligations and notwithstanding which party proposed them.

We proceed to address the scope our authority to implement each element of AB 117 with these broad principles in mind.

IV. The CCA Implementation Plan and the Process for CCA Registration (Utility Tariff Section F)

AB 117 sets forth several procedural steps that the CCA must take - and which involve this Commission -- prior to initiation of service by the CCA. Section 366.2(c) (3) requires the CCA to develop an "implementation plan" that provides a variety of information about rates, organizational structure, operations and third party power suppliers. The implementation plan is to be filed with this Commission "(i)n order to determine the cost recovery mechanism." The Commission must "certify" that it has received the implementation plan and other relevant information it has requested and then "provide the community choice aggregator with its findings" regarding cost recovery amounts required by Section 366.2 (d)(e) and (f). In addition, the CCA must "register" with the Commission and provide the Commission with additional information "to ensure compliance with basic consumer protection rules and other procedural matters."

The parties addressed the content of the implementation plan, its use, the Commission's role in reviewing and approving the implementation plan. They

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also discussed the relevance of the requirement that CCAs register with the Commission.

The utilities view the implementation plan as a commitment by the CCA, and they believe this Commission should exercise its authority over the substance of such plan. They believe the Commission should be able to review the plan, inquire as to its contents, and, if necessary, disapprove the plan. They propose an advice letter process and its associated formal review and approval process. The utilities also believe the Commission has the authority to "decertify" a CCA's authority to provide service and to entertain formal customer complaints against the CCA. As part of the registration process, the utilities and ORA propose each CCA submit a "provider service agreement" with the serving utility and, for those CCAs that are not scheduling coordinators, a signed agreement with an authorized scheduling coordinator.

The utilities argue that a local review and comment process required by AB 117 for a CCA's implementation plan may not achieve the legislature's general objectives of "detailing the process and consequences of aggregation." They also suggest the Commission must oversee the type of information the CCAs provide in the Implementation Plan and to their potential customers. For example, the utilities believe the Commission should determine whether the Implementation Plan provides specific and adequate information about the CCA's program structure and whether the program is adequately funded. They would have it include rates for all customer classes, describe how costs are allocated to different customer groups, and identify which third party suppliers are providing energy services and in what quantities.

CCAs respond that the utilities have interpreted AB 117 erroneously and argue that the Legislature never intended for the Commission to assume close

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regulatory oversight of CCA operations. They argue that the Legislature has distinguished CCAs from private power sellers, which are subject to more specific regulatory procedures in Section 394. They argue that CCAs are subject to the Brown Act, which provides ample public procedures and consumer protections by requiring open meetings, public notice, and access to decision-makers and information relevant to agency operations. CCAs do not believe the Legislature intended the Commission to substitute its judgment for that of a public agency that is accountable to the community and relevant state and federal law. They also raise concerns that the procedures the utilities advocate would create an expensive and complex regulatory bar to establish community choice aggregation programs. CEC and Local Power make similar comments.

TURN generally shares the CCAs' views on the issue of the Commission's authority over the implementation plan, although it recommends an advice letter process to review an implementation plan, similar to the one the Commission has in place for local providers of 2-1-1 telephone services, as described in D.03-02-029.

Discussion. We begin by addressing the appropriate extent of our oversight of Implementation Plans. Consistent with our discussion on jurisdiction more generally, we defer to the express language of the statute. As a threshold matter, we find nothing in the statute that directs the Commission to approve or disapprove an implementation plan or modifications to it. Nor does the statute provide explicit authority to "decertify" a CCA or its implementation plan. While we agree with the utility that the Legislature could not have intended for the requirements regarding the Implementation Plan and modifications to it to be "a meaningless, perfunctory exercise," we do not agree

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that the Legislature intended the Commission to treat CCAs like utilities, which is what the utilities suggest.

A general rule of statutory interpretation suggests that where a statute provides specific guidance -- in this case on the Commission's role and authority -- its silence in a related section or on related issues implies a limit on that role and authority. (*Louise Gardens of Encino Homeowners' Assoc. v. Truck Insurance Exchange, Inc.* 82 Cal. App. 4th 648 at 657). Here, the statute *does* require the CCA to file the plan here and gives the Commission authority to request information about the plan and to register the CCA. We assume that if the Legislature intended for us to regulate the CCA's implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent.

The Legislature's treatment of private power sellers - ESPs - is also instructive here. Section 394 sets forth an elaborate regulatory process for the registration of ESPs that seek to sell power to individual customers, a business relationship commonly referred to as "direct access." Section 394 requires ESPs to register with the Commission, to be subject to finger printing and a criminal background check, to file formal applications for authority to operate under certain conditions, and to prove technical, financial and operational ability as a precondition to the Commission's issuance of a license to operate. The Commission is explicitly provided authority to deny a license under certain circumstances and to revoke it. Section 394(a) explicitly exempts public agencies, such as CCAs, from its provisions. If the Legislature had intended the Commission to impose these types of procedures on CCAs, as the utilities suggest either directly or by inference, we must presume it would have so stated.

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Since it did not, we must assume the Legislature intended a much more limited role for the Commission in its oversight of CCAs.

We may agree with the utilities that the implementation plan - or some other document - should disclose relevant information to CCA customers and prospective customers. However, we do not agree it is our job to determine what that information should disclose. Instead, we believe it is up to the CCA to comply with the statute. This view is supported by the Legislature's historical treatment of local governments that operate utilities for such commodities as electricity, sewage treatment and water. We have no evidence to suggest that utility operations performed by local government have failed to operate successfully absent strict state oversight. CCAs are government entities subject to specific statutes with regard to their operations, decision-making procedures and information disclosure. No one has claimed that those statutes are inadequate to protect local citizens and we choose not to second guess them.

Because we do not believe the AB 117 intended to give this Commission broad jurisdiction over CCAs, we reject the utilities' proposal to subject CCAs to the advice letter process, a formal administrative procedure that the Commission employs for the purpose of authorizing changes to the tariffs of regulated utilities. The procedure would require the formal adoption of a CCA's implementation plan at a public meeting following the filing of formal comments by parties, the issuance of a proposed resolution, and the filing of comments on the proposed resolution, a process that would take no less than 60 days and would probably take much longer. Nothing in the statute authorizes the Commission to conduct this elaborate and time-consuming procedure.

While we part company with the utilities on the issue of how much authority we have over CCAs and how much formal Commission process is

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required or authorized by AB 117, we realize that the Commission has a role in assuring the CCA's operations comport with utility tariff requirements and rules, especially in the early years of the program while the utilities and CCAs are implementing an untested program. We also recognize that CCA operations or implementation plan modifications may not be consistent with the requirements of the utility's tariffs. We therefore adopt certain procedures to promote understanding and cooperative relationships between the utilities and CCAs.

In order to facilitate the smooth operation of the CCA where its policies, practices and decisions may affect the utility and its customers, we will direct the Executive Director to develop and publish the steps of an informal process of review that provides a forum for the CCA and the utility to understand the CCA's implementation plans and assures the CCA is able to comply with utility tariffs. We expect the process to be collaborative and, if required, facilitated by Commission experts. The process would be mandatory only at the request of either the utility or the CCA and where the request is presented in writing with a recitation of disputed items or areas of concern. The process would implicate no approvals, either formal or informal, from the Commission. Where the CCA fails to conform to approved utility tariffs, the utility may, in fact *must*, decline to provide service to the CCA. If a utility refuses to facilitate the CCA's initiation of service, or declines to provide service to the CCA, it must inform the CCA of its reasons in writing. If the CCA believes it or its customers have been improperly refused utility service, whether before a CCA's service is initiated or in a case where the utility interrupts CCA services, the CCA may file a formal complaint with the Commission, which may be litigated or mediated using our usual procedures. We will direct each utility to include a description of this process in

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its tariffs but we will not delay implementation of the Phase II tariffs or the CCA program generally while the informal process is being developed.

We will also direct our Executive Director to prepare and publish instructions for CCAs and utilities which would include a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate CRS, and registration of CCAs. Attachment D provides an illustrative timeline for such activity. The process and the timeline shall be consistent with the statute and with this order. The CCA's registration packet shall include the CCA's service agreement with the underlying utility and evidence of insurance, self-insurance or a bond that will cover such costs as potential re-entry fees, penalties for failing to meet operational deadlines, and errors in forecasting.

The procedures we adopt are designed to comply with AB 117 and facilitate a CCA's program while protecting utility customers. They will require a commitment by each utility and CCA to work cooperatively and in good faith. We are also aware of the particular responsibility of the utilities that is imposed by Section 366.2(c)(9), which requires the utility to "cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs." The failure of a utility to cooperate in good faith with a CCA could cause the CCA or utility bundled customers to incur unnecessary costs and create unnecessary customer confusion. In our role to regulate the utilities that are the subject of this subsection, if we find that a utility has failed to comply with Section 366.2(c)(9) or relevant Commission orders, we retain authority to impose substantial penalties on the utility and cooperate in any law suit that seeks material damages. Fortunately, at this point, we have no reason to assume that our authority will be required in this regard.

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V. Consumer Protection

The utilities and the CCAs disagree about the extent to which AB 117 requires or permits the Commission to regulate consumer protections. The utilities interpret the statute broadly to require the Commission to promulgate a number of rules and to take action if the CCA fails to provide promised benefits to consumers, if rates are unexpectedly changed or where customers are defrauded. They propose CCA customers should be able to file complaints at the Commission and that CCAs be required to file annual reports. The utilities and ORA propose protections against "slamming" by CCAs, that is, the transfer of a customer to the CCA without authority.

CCAs object to the utilities' broad interpretation of the statute and argue that the Commission has no jurisdiction over consumer complaint procedures, and protections against slamming and fraud.

Discussion. Many of the issues we resolved our Phase 1 order and those we address in this order are surely "consumer protection" in every sense of the word. The CRS protects utility bundled customers from assuming the costs incurred on behalf of CCA customers. The rates we set for CCAs are intended to protect CCA customers and utility bundled customers from having to subsidize each other. The operational requirements we order in utility tariffs protect CCA and utility customers from compromises to the engineered electrical system and the reliability of electrical service. As the statute requires, we establish procedures for notifying customers of the CCA's program and their options for future electrical service.

On the other hand, we see a very limited role in other types of consumer protections for reasons we have already discussed with regard to the jurisdiction conferred by AB 117. Nothing in AB 117 suggests that we act as a forum to

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negotiate or rule on disputes between CCAs and their customers. Many local governments provide utility services and we have no evidence to suggest their consumer protections are lacking. Section 394 exempts public agencies from submitting to the Commission's consumer complaint procedures, presumably because they have their own. Section 366 explicitly exempts CCAs from procuring a "positive written declaration" by the customer, a requirement for private aggregators and direct access providers intended to prevent "slamming." Moreover, if we impose elaborate slamming protections on CCAs, we wonder why the utilities should not be subjected to the same procedures.

For these reasons, we do not intend to act as a forum for CCA customer complaints and we assume CCA customers will have the same recourse for their electricity services as they have for other utility services provided by local agencies.

We agree with the utilities that we require certain types of information from CCAs in our role to oversee the electric system generally, including resource adequacy requirements, and there is no question of our authority to require relevant information from CCAs. The CCAs do not object to filing annual reports with certain types of information and we will direct them to provide such reports, such as those they would provide to their own local oversight agencies or bodies.

Finally, the utilities have proposed that their tariffs serve as a resource for CCA customers by specifying all program rules, including those over which we may not have authority. We have stated our intent to use utility tariffs to govern the relationship between CCAs and serving utilities. However, utility tariffs are not the appropriate place to govern relationships between CCAs and their customers. In general, utility tariffs may not regulate the activities of CCAs in

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ways that are otherwise outside the scope of this Commission's authority, consistent with this order.

VI. Customer Notices (Utility Tariff Section H and Section I)

Section 366.2 (c)(13) requires the CCA to send notices to prospective customers so each customer is able to make informed decisions about whether to take service by the CCA or "opt-out" of CCA service and remain as a utility bundled customer. The law requires the CCA to send two notices before the switch-over and two notices after the switch-over.

The utilities presented a standardized notice to customers that is similar to the one the Commission requires ESPs to send direct access customers, pursuant to D.98-03-072. Utilities express concerns that CCAs cannot be relied upon to provide good information to customers and should not have discretion to create their own notices.

The CCAs propose that a CCA's notice be reviewed and approved by the Commission's public advisor to assure the notice is adequate and accurate. CCAs and King's River oppose the utilities' proposal to oversee the CCA's notices in any way. The CEC comments the list of items the utilities would include in the CCA's billing notice would confuse and overwhelm customers. Local Power advocates in favor of the Commission requiring the utilities to include CCA notices in utility bills.

Discussion. Section 366.2(c) (13) requires the CCA to notify customers of its plans to provide service and the customer's option to remain with the utility as a bundled customer. It also permits the Commission to order the utility to mail the notices, at cost, in regular monthly bills.

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With regard to the type of information to be provided to customers in the notices, we have no reason to assume an agency of local government is incapable of complying with the statute and providing reasonable notice to potential customers. We appreciate the CCAs' willingness to work with our Public Advisor whose expertise in this area will help assure the notices are clear, complete and easy to understand.

We also direct the utilities to include in their tariffs a cost-based service that permits CCAs to include their customer notices in utility bills or, at the CCA's option, a similar mailing. We order these billings services because they may provide more efficient ways to notify customers than requiring the CCAs to mail notices separately. Because AB 117, a state statute, permits the Commission to require this service to CCAs, we do not address the relevance of the US Supreme Court's decision in *PG&E Co v. PUC* (475 US 1, 1986), which found that PG&E did not have to permit a third party to use the "empty space" in PG&E's monthly bills. Suffice to say, the information in CCA notices would directly affect PG&E's services to existing customers, would be a communication of a government agency, and would be reimbursed at cost, all of which distinguish the circumstances here from those presented to the Court in the *PG&E v. PUC* case. The information in the customer notices shall be limited to that required by Section 336.2(c)(13)(A).

We adopt the CCA's proposed tariff language that provides that the customer would become a CCA customer if the customer notice were to be returned to the utility unopened. AB 117 requires that every customer be served by the CCA unless the customer opts-out of the CCA's service. Because an unopened letter is not a proxy for a customer's opting out of CCA service, the customer must be assigned to the CCA. The customer will subsequently receive

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effective notice of his assignment to the CCA in the bill and may choose to opt out at a later date.

We also direct the utilities to provide a tariffed service, at cost, that permits the CCA to notify customers of their opt-out-options.

Further, we reject the utilities' proposal that customers with commodity contracts must opt-in to be served by the CCA. Section 366.2(c)(2) states clearly that "If no negative declaration is made by a customer, that customer shall be served through the community choice aggregator program." The statute makes no exception for customers with commodity contracts. The utilities must therefore cut-over such customers to be served by the CCA unless those customers have provided a declaration stating a wish to remain with the utility. Customers with contracts that provide for penalties for failure to fulfill the contract terms would be subject to those penalties if they fail to opt-out of service with the CCA. We encourage the utility and the CCA to inform such customers of the potential contractual impacts of taking service from the CCA.

Finally, we share the concerns of TURN and the CCAs that there is little if any benefit from permitting a battle for market share between CCAs and utilities. Of course, we expect utilities to answer questions about their own rates and services and the process by which utilities will cut-over customers to the CCA. However, if they provide affirmatively contact customers in efforts to retain them or otherwise engage in actively marketing services, they should conduct those activities at shareholder expense. We d not believe utility ratepayers should be forced to support such marketing.

VII. CRS Vintaging

In the Phase 1 order, D.04-12-046, we stated our preference for "vintaging" the CRS. The term as we use it here refers to a policy under which

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the CRS is calculated separately for each generation of CCA thereby reflecting the specific liabilities associated with the customers of each CCA according to the date the utility ceases to procure power for CCA customers.

DWR informally presented a method for vintaging the CRS, which the parties appear to endorse. It would preclude cost-shifting by assuring that a CCA's customers pay for costs incurred on their behalf but not the costs of other CCA customers.

The utilities support the concept of vintaging and specifically propose the following:

(1) Calculating the CRS as proposed by DWR/Navigant, which determines the difference between the hourly average cost of power in the utility's procurement portfolio and the market price;

(2) The CRS should be calculated every year but only once a year and assigned to the CCA's customers according to the date of initial service by the CCA or according to the terms of the commitment the CCA makes to the utility;

(3) Phase-ins should be completed within the first year, or CCA customers should be responsible for utility power liabilities until the phase-in is complete;

(4) Each CRS should be calculated each year in the DWR revenue requirement proceeding;

(5) Each CRS should be trued-up according to actual costs incurred two years prior, as information becomes available;

(6) The CRS should include the costs of (a) "resource adequacy," even if those costs were incurred after the CCA's initiation of service because the utilities have a duty to serve; (b) the above-market costs of power contract obligations required by the state, such as qualifying facility (QF) contracts, even if they were

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incurred after the CCA initiates service; (c) a share of the costs of power purchase contracts incurred to maintain transmission system reliability that are not recoverable through rates adopted by the Federal Energy Regulatory Commission (FERC).

(7) CCAs must comply with Commission requirements as a condition of receiving a vintaged CRS.

ORA generally supports the utilities' vintaging proposals.

CCAs support vintaging but object to some of the utilities' related proposals. They strongly oppose the inclusion of any additional costs in the CRS, such as QF contract costs or resource adequacy costs. They also strongly oppose any limits on phase-ins, especially in cases where the phase-in would reduce costs for the utilities and/or the CCA. Finally, they oppose the inclusion of Renewable Portfolio Standard (RPS) contracts in the calculation of the CRS, arguing that they are already liable for RPS costs. TURN agrees with the CCAs that including RPS contracts in the CRS would result in an "inequitable commingling of utility and CCA RPS procurement."

Discussion. The purpose of CRS vintaging is to assure that a CCA's customers assume liability for stranded costs associated with power procured for them but not for those costs incurred on behalf of other CCA customers. The differing liabilities between CCAs would occur where CCAs initiate service of different dates or, more likely, commit to different in-service dates.

We adopt the DWR's method for calculating the CRS, which is based on the difference between the hourly average cost of power in the utility's procurement portfolio and the market price, and consistent with our decision in Phase 1 of this proceeding. No party objected to this methodology and many are now very familiar with it. We appreciate DWR's assistance with this effort. As

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the utilities propose, a forecast using the DWR method would be adopted once a year in the proceeding used to develop DWR's revenue requirement, and then trued-up for the period two years prior as information about actual costs becomes available.

DWR observes that in R.02-01-011, the Commission is reconsidering the methodology for calculating the CRS as it applies to direct access and departing load. It recommends we state our intent to conform the CCA to whatever is adopted in that proceeding following the efforts of a working group to improve accounting of financial losses. We generally agree that the technical work in R.02-01-011 should be applied to CCAs to the extent it would reflect utility losses associated with CCA load migration. Section 1708 requires notice and opportunity to be heard prior to modify as a Commission order. We must, therefore first consider the matter formally as it applies to CCAs and intend to do so following a decision in R.02-01-011.

We do not agree with TURN and the CCAs that utility RPS contract costs should be excluded from the CRS. TURN and the CCAs suggest that since CCAs will not get any credit for utility RPS liabilities when they turn out to be priced below market, CCA customers should not have to pay for those liabilities when they are priced above market. While we recognize that CCAs will not get the benefit of utility RPS costs that are below market, this circumstance does not distinguish RPS costs from any other costs included in the CRS. The statute requires that we set the CRS so as to make bundled customers indifferent to the CCA's offering of service. Excusing CCA customers from RPS liabilities incurred originally on their behalf would force utility customers to make up the difference in violation of AB 117. For these reasons, we direct the utilities to include stranded RPS costs in the CRS calculation.

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The CRS shall not be increased to account for cost increases associated with QF contracts that the utilities renew once the CCA is offering service. QF contract renewals should account for the load reduction associated with CCA operations, consistent with AB 117, which relieves CCA's utility power purchase liabilities incurred after the CCA initiates service.

The utilities also propose strict limitations on phase-in of CCA customers. We addressed the issue of phase-ins in D.04-12-049 where we stated,

> the barrier to a pilot program or phase-in would not be the law but the possible additional costs of administering the cut-over of customers from the utilities to the CCAs that might occur, for example, as a result of differing load profiles and shifting procurement requirements, as ORA suggests. PG&E proposes a limited phase-in that might actually mitigate costs. We direct the utilities to propose tariffs that offer a phase-in at rates and charges that would recover such costs, consistent with other portions of this order addressing implementation and transaction costs. Their tariffs should permit the utilities to negotiate with the CCA to phase-in the CCA's program in ways that promote cost-savings, as PG&E suggests, and the associated cost savings should be reflected in the negotiated outcomes. (D.04-12-046.)

The utilities appear to have ignored the spirit if not the letter of this language on the subject of phase-ins. Instead of proposing ways to minimize costs, their tariff proposal permits them to charge unspecified rates for phase-ins. The tariff proposal also fails to recognize our view that the statute does not restrict phase-ins because it requires that all customers be cut-over within a year. As we stated in D.04-12-046, the statute does not restrict phase-ins in any way, including those applicable to residential customers. Accordingly, the utilities' tariffs may not include any language limiting phase-ins. The tariffs should specify the reasonable costs of phase-ins and each utility's obligation to

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cooperate with CCAs to cut-over groups of customers in ways that minimize utility and CCA costs.

The utilities propose that if they are required to take on the responsibility of assuring resource adequacy for CCA customers, CCA customers assume the associated cost. D.05-10-042 found that CCAs will be subject to annual resource adequacy requirements and will be subject to penalties for failure to meet those requirements. The CRS should therefore include no costs related to resource adequacy other than those that may have been incurred on behalf of CCA customers before the date specified in a binding notice of intent, or the date customers are actually cut-over to CCA service.

We do not understand the significance of the utilities' proposal to make the CCA's compliance with Commission rules a condition of paying a CRS that reflects the CCA's liabilities. We interpret AB 117 to require us to develop a CRS for each CCA that avoids cost-shifting and we expect CCAs to comply with Commission rules. We find no reason to make the CCA's compliance with Commission rules a condition of paying a CRS that reflects CCA liabilities.

Finally, consistent with AB 117 and our view that CCA customers pay for those power purchase liabilities that we incurred on their behalf, we find that the customers of a CCA that has phased in its program would be charged a CRS according to the date of those customers' phase-in. To apply the CRS of the last phased-in year to all customers, as the utilities suggest, could subject existing CCA customers to new liabilities or require ratepayers to assume liabilities incurred on behalf of CCA customers, contrary to AB 117's prohibition against such cost shifting.

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VIII. Open Season

The most controversial issue in this phase of the proceeding is the process for planning a CCA's cut-over and how to determine at what point the serving utility's power purchase liabilities will no longer be included in the CRS. The primary objectives of this process are to mitigate costs incurred by CCAs and the serving utilities and to provide a mechanism for coordinating a CCA's cutover. Our Phase 1 order, D.04-12-046, found that an open season would limit the CCA's liabilities for utility power purchases and provide information upon which the utility could rely about when to stop purchasing power for future CCA customers. The dispute is over the details of this commitment.

The utilities propose that in order to be relieved of prospective power purchase liabilities, the CCA must make a binding commitment to a five-year forecast of the CCA's load as of a date certain. This commitment would be made during an open season period between January 1 and February 15 of each year. The utilities would also require a Commission decision directing the utility to stop procuring load for the CCA's customer, arguing that this decision is needed to provide assurance to the utility that its procurement decisions would not be second-guessed at a later time. The CCA's five-year forecast could be modified during each year's open season without penalty. CCAs would be forgiven forecast errors within ten percent of the forecasted amounts to recognize the difficulty of estimating the load of customers deciding to remain with the utility. Forecasting errors outside of this deadband would be subject to penalties.

CCAs object to the utilities' proposal because it imposes forecasting liability on the CCA for utility load. The CCAs argue the resource adequacy forecasting process adopted in D.04-10-035 anticipates a forecasting and power purchase planning process that obviates the need for the duplicative and

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punitive process the utilities propose as part of the open season. CCAs believe the utility proposal would make CCAs liable for forecasting errors even in cases where the utility actions were the cause of the CCAs' nonperformance.

TURN and CCSF proposed an open season process that provides (1) a specific cut over date for commencement of CCA service; (2) a list of the customer classes the CCA will offer service to; and (3) a cooperative load forecasting process. CCAs would be subject to fees only in the event that they failed to accept the transfer of customers on the specified date. The fees would be equal to the incremental cost to the utility of continuing to serve the customers.

Local Power objects to the concept of an open season generally. It argues that an open season unreasonably requires the CCA to assume risk. It argues that AB 117 requires the CCA to initiate service within 30 days of the date it signs a contract with the utility and that the open season creates a circumstance which is almost impossible for the CCA to accommodate.

Discussion. As a preamble to our discussion, we refer to D.04-12-048, which we issued in the long-term procurement proceeding the same day we issued the Phase 1 decision in this proceeding, and which states:

> A CCA may execute a binding notice of intent with a commitment to a target date, at which the CCA is responsible for its own energy procurement and resource adequacy. If the CCA does so, its customer will not be responsible for stranded costs of any utility commitments entered into after the agreed upon date. However, if the CCA does not meet the target date, it will be liable for any incremental costs that the utility incurs in excess of its average portfolio cost to serve the load that the CCA is not able to serve. (Finding of Fact 29, D.04-12-048.)

The objective of a binding notice of intent is to transfer liability for customer power purchases from the utility to the CCA according to a specified

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date and in so doing minimize the liabilities of all customers for stranded costs associated with power purchase commitments. While this latter objective sounds simple, its accomplishment may not be, given the many variables and contingencies inherent in the open season process.

The utilities propose a voluntary annual open season at which time CCAs would make that binding commitment. It would occur between January 1 and March 1 (or February 15, depending on the available date of the California Energy Commission's resource adequacy load forecast) and appears to require a standard format that would apply to all CCAs equally. We agree with the utilities that the open season provides a reasonable procedure for getting CCA binding commitments and we agree that they are necessary in order for the CCA to be assured of limiting its liability for utility power purchases.

We do not agree with Local Power and CCSF that the filing of an implementation plan or the creation of the CCA must automatically trigger changes in utility procurement practices. In some cases, the utility may be able to modify procurement strategies without imposing additional cost or risk on utility customers. As the utilities observe, however, if the CCA never initiates service, changes in procurement in other cases may ultimately be costly to utility customers. To the extent the CCA is willing to make a commitment, even tentatively, there may be ways to mitigate procurement costs. For example the CCA and the utility may enter into a preliminary agreement whereby the CCA assumes some liability for changes in power purchase strategies in exchange for relief from other risks. In all cases, the utility must reasonably manage procurement consistent with Section 366.2, which provides that CCAs must assume only the "net unavoidable costs" of utility power procurement. While we recognize the uncertainties the utilities face in trying to forecast load loss prior to

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receiving a CCA's binding commitment, we also believe the utility should take reasonable steps to plan for that contingency, for example, by reducing long-term commitments until a CCA's plans are assured. In any case, the uncertainties of procurement planning are not novel and are addressed in considerable depth in proceedings relating to utility procurement plans and in accordance with other law.

We do not believe that AB 117 limits the Commission's discretion to adopt a process for a binding commitment between the utility and the CCA, as Local Power suggests. The statute certainly anticipates the Commission's adoption of the administrative elements of the program that are responsible and practical. An open season and the requirement for a binding commitment are reasonable tools for implementing the statute and recognize several elements of the statute designed to facilitate CCA operations while protecting utility customers. The binding commitment is a reasonable way to balance the interests of the utilities and the CCAs with regard to the parties' mutual understanding and the limitations on their respective liabilities. If a utility and a CCA are able to develop an agreement that is tailored to the more specific circumstances at hand, so much the better. With all of this in mind, we concur with the utilities and TURN that a CCA that declines to participate in the open season is liable for any power commitments made on behalf of its customers up to the date the CCA begins operations. An exception to this rule would be where the utility and the CCA can craft a binding commitment outside the open season that is tailored to the CCA's circumstances.

Although we adopt the utility open season proposal in concept, some of its details require modification. Specifically, we reject that portion of the proposal would require CCAs to assume the risk of utility load forecasts for five years,

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which would be required under the utilities' proposal for the CCA to pay for any variations from forecasts for the departing load of CCA customers. This proposal effectively requires the CCA assume liability for utility forecasts, a risk that is properly the utility's. Currently, the utilities have information about the number and type of customers they serve and they forecast demand accordingly and, by all accounts, well. The utilities are adept at forecasting customer load because they have historic customer information and technical resources. The utilities routinely modify system load forecasts when they gain or lose customers, in light of changing usage patterns and other circumstances. The departure of CCA customers from a utility's system is no different from any other change in system load the utility may experience except that the lost load may be larger. When a group of customers transfers from the utility to the CCA, the utility still has the information and expertise it requires to forecast the change in its system load. The utility should assume responsibility for the final forecast of its total load, just as it assumes that responsibility today. Under this policy, the CCA retains responsibility to forecast its own load and assumes all risk and costs where the forecast and demand vary for its own customers.

Although we reject the utilities' proposed requirement that CCA's assume risk for five years of forecasting departed load, we recognize the need and opportunity to minimize the risk of forecasting that is imposed on utility customers. TURN's proposal for a collaborative forecasting process appears to be a reasonable compromise with some modifications. TURN would require the CCA and the utility to work together to determine the load that would be transferred to the CCA. We understand the utilities' concerns that the collaborative forecasting process may not provide strong incentives for the CCA to work with the utility on developing a reasonable forecast. For that reason, the

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open season rules should require the CCA to disclose which portion of each class of customers would be subject to a cut-over. As the utilities propose, the open season rules should also require the CCA to provide all relevant information about the number of customers to be cut-over, the rates, rate design and special contracts to facilitate forecasting. All of this information would be provided to the utility confidentially and, at the option of the CCA, subject to a nondisclosure agreement. As the utilities propose, where a CCA initiates service before or after the date of its commitment to the utility, the CCA will be responsible for all incremental costs incurred by the utility.

To account for the possible failure of the collaborative forecasting process, we also adopt TURN's proposal to establish default opt-out figures for the first year of the CCA's operation, which will spread the forecast risk of this type of uncertainty. Because we do not adopt the utilities' proposal for the CCA to assume forecast risk, the main purpose of the default opt-out percentage is to estimate the cost to the utility in the event a CCA misses its cut-over date. The default opt-out forecast will be 5% for residential customers and 20% for commercial and industrial customers unless the CCA and the utility agree to other amounts. The purpose of this collaborative forecasting exercise generally is to limit the risks of the utilities and the CCAs. If we find in the future that it fails to accomplish that goal, we will reconsider it.

Of course, utilities' bundled customers should not assume the risk for a CCA's failure to transfer customers on the date to which the CCA commits if the CCA is responsible. Where the CCA is responsible it should pay the utility's incremental cost of the delay that is related to power purchases. Where the CCA is not responsible, it should credit the CCA with the incremental cost of its power purchase losses. If the CCA believes the utility is at fault and the utility does not

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agree with its culpability, the CCA should file a complaint seeking credit for power purchase costs. If the CCA seeks damages, it must file suit in a court of law because this Commission has no authority to award damages, as distinct from reparations, which are essentially refunds of billed amounts. In any of these cases, we encourage the CCA and the utility to seek assistance with alternative dispute resolution. If the CCA is not responsible for the delay, the extent of the utility's financial liability would be determined in the ratemaking proceeding that addresses procurement costs. The utility shall not be reimbursed for such costs absent a finding from the Commission that it may include such costs in rates . As TURN observes, the CCA and the utility may and should mitigate risk associated with forecasts by agreeing in advance that the party who has too much power will sell the power to the party who is short on power. We will direct the utility to include such a provision in its tariffs.

We agree with TURN that a CCA submitting a formal notice of intent under the open season tariff has automatically provided a "self-executing" notice that relieves the utility of its power supply obligations. Requiring a Commission order, which the utilities suggest, would unnecessarily add cost and delay to this process.

The CCA's proposal for the utility and other parties to keep a CCA's open season information confidential is reasonable. If knowledge of a CCA's cut-over date and costs were to become public, the CCA could be vulnerable to price gouging by potential power suppliers.

In sum, we find that a voluntary open season in which the utility and the CCA work cooperatively to reduce risk and stranded costs is reasonable. We encourage the utilities and CCAs to tailor their agreements to minimize costs and promote cooperation wherever possible. In the open season tariffs we adopt

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today, the utilities are responsible for their load forecasts once the CCA has begun operations just as the CCA is responsible for its load forecasts, although we adopt measures designed to facilitate good utility forecasts. The CCA's open season agreement is a binding commitment under which it assumes all liability for delays in implementation except those attributable to utility actions. While voluntary, if the CCA chooses not to participate in the open season or to sign a more tailored binding agreement with the utility, the CCA must assume the risk for all utility power purchased up to the CCA's initiation of service. The CCA's binding commitment for an in-service date, in combination with the approaches we adopt today to mitigate risk, represent a reasonable middle ground that is sensible and fair to bundled customers, utilities, CCAs and their procurement customers. Attachment B, proposed by TURN and adopted herein with the minor exceptions we discuss, describes the open season and should be included in each utility's tariffs.

IX. Renewable Portfolio Standard

Section 399(12)(c)(2) requires the Commission to consider whether CCAs should be subject to renewable portfolio standards (RPS), that is, requirements for the amount of renewable resources included in the CCAs energy portfolio. The utilities argue that the CCAs should be subject to the same requirements as the utilities. CCAs believe that Section 399 is generally irrelevant because Section 387 requires RPS standards to be implemented and enforced by the local governing body of a public utility, which CCAs argue includes them.

As CEC suggests, we believe it is appropriate for the CCAs to identify in their implementation plans how they intend to comply with RPS requirements, although we defer to the statute on what the implementation plan requires. We

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are considering the matter of the RPS standard's applicability to CCAs in R.04-04-026 and will resolve the matter there.

X. Other Tariff Rates and Services

Utility tariffs must specify the nature and types of services to be provided to the CCAs. We discussed these in general in D.04-12-046 and also how the utilities should set fees for CCA services. Generally, we found that the fees should be based on incremental costs. We determined that the utilities could not impose a fee where it was already recovering related costs as part of its revenue requirement. In such cases, we invited the utilities to implement CCA fees as part of general rate cases and reduce overall revenue requirement accordingly so that they were not recovering costs twice.

We address the controversies regarding utility CCA tariffs mindful that the purpose of those tariffs is to govern the relationships between CCAs and utilities, not CCAs and their customers, consistent with our previous discussion.

The following addresses controversies between the parties on several issues. Attachment A summarizes the adopted treatment of each tariff provision.

1. Treatment of New Customers

CCAs propose that customers moving into the area be automatically enrolled as CCA customers and that CCAs not be subject to the costs of the utility generating an associated CCA Service Request or "CCASR." Utilities respond that they must generate the CCASR or else the customer would be automatically assigned to the utility as a bundled customer.

The utilities also object to what they believe is the CCAs' attempt to subvert statutory requirements to notify new CCA customers of the opportunity to opt out during the first 60 days without penalty.

We agree with the CCAs that new customers be automatically assigned to

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the CCA, which is consistent with AB 117's requirements that customers opt-out rather than opt-in. However, the utilities should be permitted to charge for the cost of each CCASR if they must generate one for a new customer.

Like the utilities, we interpret the statute to require notification to all customers – including those who initiate service after the CCA's initial cut over -- of their opportunity to opt-out of CCA service within 60 days of service without penalty. Consistent with our previous discussion of Commission jurisdiction, however, the statute requires the CCA to comply with the statute and does not provide either the Commission or the utilities with authority to enforce the statute. For that reason, the utility tariffs may not make this notification a condition of service.

2. Boundary Metering (Section O)

The utilities propose tariff language that requires the utility to install, maintain and calibrate metering devices. The CCAs propose to include tariff language that would permit their vendors to undertake these activities. Section 366.2(c) (18) gives this authority to the utilities. We therefore agree with the utilities that the CCAs' vendors should not be permitted to provide these services.

3. Customer Information

The utilities object to the CCAs' proposal for the utility to provide "all contact and energy usage data for all customers within the CCA's service territory" in advance of the CCA's mass enrollment process. The utilities believe the CCAs do not need this information because it might include information they do not need about customers who will ultimately opt-out of CCA service.

D.04-12-046 issued in Phase 1 of this proceeding directs the utilities to provide all relevant information to CCAs and prospective CCAs, consistent with

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Section 366.2(c)(9). In that order we stated "AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data even before the CCA begins offering service." We have found that AB 117 does not permit the utilities to second guess a CCA's request for relevant information and we will not revisit the issue here. The utilities' tariffs, therefore, shall include a provision that permits CCAs to access all relevant customer information, consistent with D.04-12-046 and the tariffs filed in compliance with D.04-12-046.

4. Customer Switching Rules

The CCAs propose that a CCA customer that switches to utility bundled service should be committed to that service for one year rather than the three-year commitment required for ESP customers switching to bundled service. The utilities object to this proposal, believing it to be unlawful. They also object to the CCA proposal that distinguishes between customer sizes with regard to the amount of advance notification to the utility required of the customer. Customers with loads great than 200 kilowatt (kW) would have to give six months notice while smaller customers would need to provide only 30 days' notice. The utilities state this distinction based on size is not applied to customers of ESPs and is therefore unlawful.

Section 366.2(c) (11) states that "customers that return to the electrical corporation for procurement services shall be subject to the same terms and conditions as are applicable to other returning direct access customers." This language clearly provides that CCA customers are to be treated like direct access (DA) customers when they switch between procurement providers. Currently, a DA customer must make a three-year commitment to the utility when it returns to bundled service and notice requirements for switches to the CCA are the same for customers of all sizes. The utilities are correct that their tariffs for CCAs must

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track these provisions.

5. The Utility-CCA Service Agreement

The utilities append a draft service agreement to their tariffs which would memorialize the understandings between the utility and the CCA prior to the CCA's initiating service. The proposed service agreement is comparable to the one we have adopted for ESPs and no party objects to it. We adopt it with the understanding that it is exemplary and may be tailored by the mutual agreement of the utility and the CCA to accommodate specific circumstances, as long as utility bundled customers would be no worse off as a result. The utilities included a draft service agreement as part of their open season proposal, which would be signed by the CCA and the utility before the CCA initiates service. Additionally, the utilities should modify their proposed Service Agreement to conform to the findings in this order and submit it with their proposed tariffs in compliance with this order

6. Call Center Fees

The utilities propose to charge CCAs "call center fees" when a CCA customer calls seeking information. The CCAs oppose these fees, believing the utilities are already reimbursed for such costs.

In Phase 1, we addressed the issue of call center costs and were not convinced that the utilities had demonstrated that the CCA program will increase call volumes. Moreover, the utilities are already reimbursed for call center operations. D.04-12-046 found that the "utilities should track and recover incremental call center costs by establishing an 800 number." In general, we found that costs already recovered in a utility's revenue requirement for an existing utility operation may not be the subject of CCA fees until the Commission has made revenue requirement adjustments in general rate cases.

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The utilities have not yet tracked CCA calls and it is therefore premature for establishment of an 800 number and associated charge. Thus, the utilities misinterpret D.04-12-046 in arguing that it authorized recovery of these fees prior to presenting compelling evidence that the associated costs are incremental. We decline to include call center fees at this time and restate our policy that the utilities should address this matter in general rate cases where the proceeds from individual rates to CCA customers offset revenue requirements allocated to other customers and thereby make the rate change revenue neutral.

7. Opt-Out Fees

The utilities propose opt-out fees that would be charged to recognize the costs of processing a customer's decision to remain with the utility as a bundled customer.

CCAs object to being charged for opt-out fees because the utility is effectively getting a new customer, a situation the CCA should not have to subsidize. CCSF proposes that PG&E's service include an option for customers to opt-out using the internet and to reduce costs by providing the option to use a post card instead of a letter.

Utilities respond that a post card process is unlikely to save costs. PG&E does not have a system for processing post cards and would have to create a website for option. It is willing to explore the internet option and revise its tariffs at a later date.

The Commission addressed the issue of whether CCAs should pay for opt-out processing. D.04-12-046 determined that this is a cost that would not be incurred were it not for the CCA's program. AB 117 requires therefore that the CCA pay for the activity. We believe our finding in that decision was correct and it should not be relitigated here. The utilities are therefore entitled to charge opt-

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out processing fees.

We will not require PG&E to revise its processing system to accommodate post cards because of the expense. We encourage PG&E to consider the use of the internet for opt-out notifications and revise its tariffs at a later date, as it suggests.

8. Customer Deposits, Partial Payments and Termination of Service

The parties were divided on the issue of how to deal with deposits, partial payments and termination of service. The utilities propose that customers' partial payments be allocated first to utility charges.

CCAs and TURN would prorate partial payments between CCA and utility services. TURN observes that the entities would then be in the same position with respect to collections and termination of service. TURN proposes a prorated allocation of deposits between the utility and the CCA as well so that CCA customers would not have the burden of providing two deposits, one for the CCA and the other for the utility.

The utilities oppose any allocation of partial payments to CCA services until all charges for utility disconnectable services have been paid. They argue the CCA/TURN proposal would promote disconnections by leaving utility disconnectable services unpaid. CCA services should not be considered disconnectable, consistent with existing Commission policy for ESPs.

We adopt the utilities' proposal that each entity collect its own deposits (although the CCA may collect the deposits using the utility's billing services). While this policy may require some customers to pay two deposits, we have consistently treated CCAs as stand-alone operations with ratemaking discretion. We adopt the utilities' proposal for partial payments as a reasonable way to protect customers from disconnections. Partial payments would be allocated

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first to disconnectable services and then on a prorated basis to other utility and CCA services. Finally, the utilities should accept customers who fail to pay CCAs for their services, consistent with their obligation to serve and consistent with other tariff requirements regarding nonpayment.

9. CCASR Processing (Section M.11)

The utilities propose a 15-day lead time to process a switch over from the utility to the CCA where there is no need for urgent action, such as following an opt-out notice or where the customer is moving and no longer requires electric service. The CCAs propose a shorter three-day turn-around.

We agree with the utilities that it is reasonable to cut over a new CCA customers after the normal meter read day, which requires a 15-day lead time.

10. Changing Municipalities in the CCA Plan

In some cases, a CCA may wish to add or remove a municipality (that is, a city or county) from its service area. This could occur if a municipality decides to withdraw from participation in the CCA or where a city or county joins a CCA.

The utilities' proposed tariff includes a detailed description of how the CCA may add or remove a city or county. The CCAs object to this section, arguing that AB 117 does not require CCAs to go through elaborate procedures when a municipality joins or leaves a CCA.

The utilities are correct that the addition of or removal of a municipality from a CCA will affect utility operations, outstanding liabilities that would affect the CRS. For that reason, the utilities' tariffs should describe a process for recognizing the change in the CCA's membership and customer base. The utilities should modify their tariff proposal to conform to the findings we make in this order regarding CCA initiation of service, for example, the procedures for filing the implementation plan and the method for calculating the CRS. These

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portions of the tariff should not require procedures or information not required of the CCA when it first files its implementation plan or initiates service, consistent with this order.

11. Confirmation Letters (Section J.4)

The utilities propose to send prospective CCA customers a formal notification of the change in the customer's service to the CCA. The utilities propose to charge the CCA for this notice. Each customer notification would be billed to the CCA at a rate of $.40 per customer, and would be levied for each customer that did not opt-out of the CCA's service. The utilities believe this notice will reduce customer confusion and assure that the customer has intended to change service to the CCA. The CCAs object to this notification and being billed for it, observing that it could cost a city like San Francisco as much as $140,000.

During the period before the CCA's initial cut-over, customers will receive four notices of their opportunity to opt-out of CCA service. Although the utilities argue that such a notice is required to inform the customer of a changed account number, we find such information may be reasonably provided in the first relevant bill, or where the customer requires it at an earlier date, the utility may provide it in response to a telephone call. It would be inefficient to provide such notices to all customers in order to serve the interests of a few. If a utility can in the future provide evidence of a costly or pervasive problem in this regard, we will reconsider our decision. We find no compelling justification for the utility's additional notification with its associated cost, which could be substantial and provides no particular benefit to the CCA or its customers in light of other notice requirements. We reject this utility proposal.

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12. Schedule Coordinator Requirements (Section B.c.3)

The utilities propose tariff language that would require each CCA to identify its scheduling coordinator(s) to the ISO and, where the CCA fails to provide such information to the ISO, the utility would have discretion to return the CCA's customers to bundled service. The Utilities argue that if a CCA's scheduling coordinator significantly under-schedules a CCA's electric load, the California Independent System Operator (ISO) will need to schedule energy on behalf of the CCA. The ISO would charge the costs of this service to other market participants, including the Utilities' bundled service customers, by way of the "Unaccounted For Energy (UFE) charge." The Utilities state that the under-scheduling of energy has occurred on several occasions when ESPs have lost their scheduling coordinators, and believe that CCA under-scheduling would unlawfully shift costs from CCA customers to bundled service customers.

The CCAs state they are not ESPs and AB 117 does not anticipate such strict oversight of CCA operations.

Discussion. AB 117 does not require CCAs to identify their scheduling coordinators to the utilities and, as we have already discussed, utility tariffs govern the relationships between CCAs and utilities, not, in this case, CCAs and the ISO. The ISO is responsible for managing its relationship with each load serving entity's scheduling coordinator, including those of CCAs. In the event that a CCA's scheduling coordinator under-schedules energy, the ISO imposes tariffed charges on the scheduling coordinator, which then passes these costs to the load serving entities. Therefore, these fees are assumed by the CCA's customers, not bundled customers. If there is some likelihood that irresponsible scheduling coordinators create liabilities for the system, the ISO is the appropriate entity to address this problem through its tariffs. Indeed, as the

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utilities recognize, the ISO already requires load serving entities to provide information about scheduling coordinators. The utility tariffs should not include any language that addresses scheduling coordinators or the CCAs' relationships with the ISO.

13. Load Aggregation (Section B.8)

The utilities object to the CCAs' proposal to permit CCA customers to aggregate load without reference to existing utility tariff restrictions. It is unclear from the record how, if at all, unrestricted private aggregation by CCA customers might affect utility operations and be affected by existing tariffs. We presume CCA's are proposing to permit their own customers to aggregate load and that the utilities object on the basis that private aggregation (that is, "direct access") is prohibited for any customers except those already aggregating load. We will consider this issue at a future time if the CCAs or the utilities wish to clarify the matter. For the time being, we adopt the utilities' language on this topic, which permits private aggregation by CCA customers only to the extent its implementation does not conflict with utility tariffs.

14. Notice of Program Implementation

The utilities propose that the Commission set the "earliest possible date" for each individual CCA's service initiation. They also propose the first CCA provide them with six months advance notice in order to have time to affect the system changes necessary to implement the overall program.

The CCAs propose language that is more specific, requiring implementation no later than 30 days after the Commission's notice of receipt of the CCA's implementation plan, or the local government's adoption of a CCA implementation plan, or the Commission's stated "earliest possible implementation date" or a mutally-agreed upon date, whichever is later.

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In proposing these differing conditions for program implementation dates, the utilities and the CCAs interpret Section 366.2(c)(8) differently. The utilities appear to believe the Commission's finding with regard to the CCA program's "earliest possible implementation date" means a date applicable to the initiation of service by each CCA. The CCAs appear to interpret that subsection as referring to the date the entire program could go into effect. The subsection states "The Commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the Commission." Because the statute is vague as to its meaning, we find the CCA and the utility interpretations are reasonable and apply the statute's provisions in the context of our overall program design.

Because we have declined to issue an order approving an implementation plan for each CCA or one that directs a utility to stop procuring power for a CCA, we apply Section 366.2(c)(8) by herein finding that the earliest possible implementation date for the CCA *program* was the effective date of the tariffs filed pursuant to D.04-12-046 in Phase 1 of this proceeding. The utilities shall immediately undertake to affect the system changes required to satisfy the tariffs as soon as it receives a binding commitment from a single CCA. It should complete its work within six months for the first CCA in its territory. The earliest possible implementation date for a CCA's provision of service would be the date of the completion of all tariffed requirements, but no later than six months after notice from the first CCA or the date the CCA and the utility agree is reasonable. In no event may the utility delay the initiation of CCA

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service once the utility has implemented the required processes and infrastructure and the CCA has fulfilled tariffed requirements.

15. Electronic Data Interchange Testing (Section F.5.d)

The utilities propose to charge individual CCAs the cost of Electronic Data Interexchange (EDI) testing, which SCE estimates will take up to 100 hours. The CCAs object to paying for this testing process.

D.04-12-046 and AB 117 require that each CCA pay the costs of program implementation activities attributable specifically to that CCA. EDI testing is one such activity. The utility tariffs should therefore require each CCA to pay for EDI testing within reason.

16. Specialized Service Request (Section E.1)

The utilities propose to charge hourly rates for specialized services, that is, those that are requested by an individual CCA and are not otherwise priced out in the tariffs. The CCAs would prohibit the utilities from charging for services that are not provided to other commodity service providers.

D.04-12-046 found that utilities should charge CCAs the incremental costs of providing services to them. The utilities tariff proposals to charge for specialized services appear consistent with this principle and we adopt them.

17. Metering Fees

PG&E proposes charging CCAs $9.28 per interval meter per month for "Meter Data Management Agent Meter Data Posting." CCAs object to the level of the fee, arguing that $6.13 of it is for software license point that PG&E does not need.

PG&E's witness clarified that the software license point is required and is an incremental cost the utilities will incur. The CCAs appear to have confused

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data processing requirements with physical metering requirements. We adopt the utilities' proposed metering fees.

18. Involuntary CCA Service Termination (Tariff Section T.1, T.2, T.3)

The utilities propose tariff provision that would permit the utilities to terminate a CCA's service to customers for a variety of reasons, among them, failure to comply with tariff requirements, failure to conform operations to the Implementation Plan, failure to comply with ISO requirements and in response to a Commission order "decertifying" the CCA. The CCAs propose removing all of this language, arguing the utilities should not have authority to determine when a CCA program should be terminated, especially since CCAs will be competitors of utilities.

Utility tariffs traditionally permit the utilities to deny service under certain explicit conditions. Those they would include in their CCA tariffs are far too vague and would provide the utilities with far too much discretion. For example, the utilities could conceivably terminate an entire CCA program for the CCA's failure to update a customer's records within three days or because of a miscommunication with the ISO. The termination of a CCA program could be extraordinarily expensive to the utility, the CCA and customers, and create enormous customer confusion and ultimately litigation. For that reason, and because CCAs are competitors as well as customers of the utilities, we will not permit the utilities broad discretion in this area. We will not permit the utilities to include any language in the tariffs that provides the utilities with discretion to terminate a CCA's service with the exception that the utility may terminate service in the event of a system emergency or where public health or safety is involved (Section T.3). Otherwise, the tariffs should specify that if the utility seeks to terminate service to the CCA it shall do so only following a Commission

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order directing the utility to terminate service. Utility requests to the Commission to terminate a CCA's service should specify the reasons for the requested termination, the impacts of the termination, and the expected impacts if the CCA's service is not terminated. We agree with the utilities that the costs of notice to customers of a lawful termination should be billed to the CCA (Section T.2)

19. Net Metering

CEC proposes the utility tariffs for CCA explicitly permit net metering for CCAs and their customers who install renewable energy. CEC proposes also that the details of this tariff offering be worked out at a later date, preferably between the CCAs and the utilities. The utilities object to CEC's proposal, arguing that it is vague and could be costly to other customers.

Net metering effectively requires the utility to pay the customer the utility's full retail price for power that is produced by the customer but sent into the utility grid. Currently, we permit net metering for certain renewable projects. We have recently addressed this issue in R.04-03-017, where we are developing policies for distributed generation in general and our Self-Generation Incentive Program (SGIP) in particular. We believe that proceeding is the appropriate venue for deciding issues relating to renewable project net metering and decline to make any decision here about whether CCAs and their customers would qualify for net metering. In that regard we would consider whether it is appropriate for utility bundled customers to pay for the high cost of net metered power produced by CCA customers.

20. Rate Ready Billing

PG&E proposes a "rate ready" billing service to the CCAs that would provide information on CCA rate structures. PG&E's proposal for "rate ready"

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billing permits the CCA to send rate information to the utility, which in turn calculates the rate for each rate tier.

CCAs object to PG&E's proposal for rate ready billing because it would not provide the customer with accurate billing information unless the CCA offered a two-tiered rate. The CCAs believe this is unreasonable since the utilities offer a five-tiered rate structure. CCAs propose that PG&E's rate ready service include the option for CCAs to elect to have PG&E bill each of the CCA's rates, notwithstanding the number of tiers charged for the commodity portion of the bill.

CCAs also object to PG&E's bundling this service and charging $.70 per bill per month, arguing that its proposal is contrary to D.04-12-046, which required unbundling for billing services.

PG&E's rate ready service is an optional offering. If PG&E and a CCA can agree to a reasonable modification to this offering, we have no objection to it, as long as it is offered at cost. Otherwise, CCA's may subscribe to the PG&E's "bill ready" service, described in a subsequent section.

21. Services Funded by Bundled Rates (Section B.2)

CCAs propose to include tariff language that would require the utilities to continue to provide CCA services supported by bundled rates "until such time that those funds and/or service obligations are transferred to a CCA or another agency by a competent jurisdiction." The utilities oppose this language as unnecessary and unclear as to its purpose.

The utilities under our jurisdiction must continue to provide tariffed services until the Commission finds to the contrary. There is no reason to include such language in the tariffs and we concur with the utilities that it should not be included in them.

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22. California Alternative Rate for Energy (CARE) Discount

The Utilities believe that eligible CCA customers should receive CARE discounts as if they had remained on bundled service, and propose ratemaking for this policy should be implemented in future rate design proceedings. The Utilities also propose that CCA customers receiving a CARE discount be exempt form paying the CARE surcharge portion of the Public Purpose Program (PPP) charge in addition to the DWR Bond charge, as utility CARE customers are. The CARE discount would be applied to all billing elements but would be credited to every customer's distribution charges. SDG&E proposed the continuation of its separate CARE line-item, calculated as if the customer were a bundled service CARE customer.

The CCA parties do not object to the utility proposals.

Discussion. The CPUC has had a long standing commitment to support low income programs such as the CARE program. As such, we believe that it is good public policy that all of California's qualifying electric customers reap the benefits of this program by receiving the CARE discount. Thus, we order the Utilities to continue to provide CARE discounts to all qualifying CCA customers as the utilities propose. The discount would apply to all elements of a customer's bill, including the CCA portion, but the discount would be applied only to the distribution rate. The utilities would calculate the generation portion of their CARE discount using their own generation rates. Bundled customers would not be subsidizing CCA customers because all customers pay for the CARE discount through either the public purpose program charge or their distribution rates (or, in the case of SDG&E, a separate line item that applies to all customers). We adopt the utility proposals for ratemaking treatment of these proposals, whether as part of distribution rates for PG&E and SCE or as a separate line-item in

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SDG&E's case. We agree with the utilities that the discount should not be reflected in the CRS.

CCAs may design rates which provide additional discounts to low income customers, a ratemaking matter that would be at the discretion of the CCA.

23. "In-Kind" Power

D.04-12-046 issued in this proceeding expressed interest in the idea of a CCA assuming liability for DWR power contract obligations for which the CCAs would be paying for as part of the CRS. The benefit of such an assumption of liability would be the potential for cost-savings for CCAs. This issue came up again in this phase of the proceeding, although the practicalities of this concept appear to remain unresolved. The DWR has expressed concerns about the administrative and legal hurdles that may arise. We restate our policy here that if DWR and a CCA can make a reasonable arrangement to take DWR power that would otherwise be undeliverable, or in some other way minimize power contract liabilities, we encourage them to do so but will rely on the parties to work out such arrangements.

24. Bill Ready Billing

An alternative to rate ready billing is "bill ready" service, under which the CCA provides all relevant billing information for each customer.

The utilities offer "bill ready" services to ESPs although apparently none take the service from PG&E because PG&E manually processes the information, which is expensive.

The CCAs object to PG&E's alternative "bill ready" service because they believe the $2.15 per customer monthly charge is exorbitant, as much as 15% of the average customer's procurement bill. CCAs state that extrapolating from this

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number suggests PG&E would need to hire 88 additional full time staff to serve the City of San Francisco's billing needs.

We agree with the CCAs that PG&E should develop an automated billing system that permits "bill ready" services, which SDG&E and SCE already have in place. It is unreasonable to expect a party to spend $2.15 a month per customer for this service, considering that SDG&E charges $.22 cents per month for the same service and SCE charges $.44 cents per customer per month. Moreover, we directed PG&E to provide bill ready services to ESPs in D.97-10-087, more than eight years ago. Although PG&E argues that we never directed it to provide "automated" services, PG&E may assume we required a service that was reasonably priced and using the most efficient technology.

We herein direct PG&E to develop an automated bill ready service for CCAs and ESPs within 12 months. PG&E agrees that it intends to do so. PG&E may charge the same rate as charged by SCE for this service. If PG&E can demonstrate in its general rate case that the amount is below incremental costs, we will consider increasing it. The costs of initial changes to the billing system should be included as part of the revenue requirement assumed by all ratepayers, consistent with D.04-12-046, since the cost would be incurred on behalf of all CCAs – and also ESPs – rather than on behalf of a single CCA.

X. Future CCA Issues

The CCA program is new in California and there is little experience with such a program anywhere. Our order today and the parties who contributed to it have sought to anticipate every contingency on the one hand and permit some flexibility on the other with the expectation that the utilities and CCAs may be able to tailor operational arrangements according to circumstances in ways that promote program efficiency and fairness. We recognize, however, that a CCA's

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operation may affect customers, utilities and the power system in ways we cannot today anticipate.

We expect CCAs may initiate service to local customers in the next year or two. Experience with their operations will undoubtedly provide experience and information about the policies and rules we adopt today. We intend for that experience to inform future inquiries and decision-making on CCA issues. Accordingly, although we close this proceeding today, we intend to initiate a new rulemaking to review the program within a year of the initiation of the first CCA's operation. In the meantime, we encourage CCAs and utilities to bring to our attention problems with existing tariffs, rules or policies adopted today. They may do so by consulting with our technical staff or filing petitions to modify orders issued in this proceeding. We will also entertain motions to reopen this proceeding and consider specific issues.

XI. Comments on Proposed Decision

The proposed decision of ALJ Malcolm in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed on November 22, 2005 and reply comments were filed on November 29, 2005. The final order adopted by the Commission contains several clarifications to the ALJ's proposed decision and a number of substantive changes.

XII. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Kim Malcolm is the assigned ALJ in this proceeding.

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Findings of Fact

1. Section 394 specifies regulatory procedures for the oversight of energy service providers but does not articulate similar requirements for CCA program implementation.

2. Although the Commission has the authority to assert limited jurisdiction over certain CCA matters, entities of local government, such as CCAs, are subject to numerous laws that will have the effect of protecting CCA customers and promoting accountability by CCAs. Existing laws applicable to CCAs would protect customers by requiring CCAs to conduct open meetings, disclose relevant information to the public and be accountable to elected officials, the courts and voters.

3. The Commission may protect utility bundled customers and utility systems by requiring the utilities to include relevant conditions of service to CCAs in utility tariffs.

4. The Commission's advice letter process is not required in order to process a CCA's implementation plan and registration with the Commission.

5. Disputes between CCAs and utilities may be able to be resolved by way of an informal facilitation or mediation procedure.

6. D.04-12-046 issued in Phase 1 of this proceeding and this order establish numerous consumer protections anticipated or required by AB 117.

7. A cost-based utility offering to include CCA customer notices in utility bills could be an efficient and effective way of notifying customers of the CCA's future plans to provide procurement services.

8. An unopened letter notifying a customer of the option to opt out of CCA service is not a proxy for a customer affirmatively declining to take CCA service.

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9. AB 117 does not distinguish customers with utility commodity contracts from other customers with regard to its requirement that customers who do not opt-out of CCA service be served by the CCA.

10. Utility marketing of procurement services to CCA customers and providing information about a CCA's services and rates to customers may create conflicts of interest and costs that may not be offset by benefits.

11. "Vintaging" a CRS is the process of calculating a CRS that reflects the power purchase liabilities incurred on behalf of a specific group of customers. Because power purchase liabilities change over time, CRS vintaging would be conducted at regular intervals to reflect those changes.

12. DWR's method for calculating the CRS calculates the difference between the hourly average cost of power in the utility's procurement portfolio and the hour market price.

13. RPS costs originally incurred on behalf of CCA customers are not distinguished by AB 117 from any other type of costs for purposes of calculating the CRS.

14. The purpose of a binding notice of intent between a CCA and a utility for a CCA in-service date is to minimize utility power purchases that might later become stranded when the CCA initiates service. This notice of intent would commit the CCA to assuming any power purchase liabilities that the utility may incur if the CCA does not initiate service according to the terms of the notice.

15. A voluntary open season may provide an opportunity for CCAs to minimize risk associated with CRS amounts and for the utility to limit its exposure to the risk of purchasing unneeded power.

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16. Imposing liability on utility bundled customers for all power purchases made after the date of the creation of a CCA or its filing of an implementation plan, absent a binding commitment, may require bundled customers to pay for power reasonably purchased on behalf of CCA customers.

17. Requiring a CCA to assume the risk of a load forecast for five years effectively shifts the risk from the utility to the CCA for part of the utility's forecasting activities. The utilities routinely adjust forecasts to account for lost load.

18. Open season rules that require the CCA to provide relevant information about its future customers, rate design, rate levels and services to the utility would help mitigate forecast risk.

19. A collaborative process whereby the utility and the CCA work together to develop a forecast of departing load, would help mitigate forecast risk.

20. Establishing default opt-out figures for the forecast of the first year of the CCA's operation would spread the risk for this type of forecasting uncertainty.

21. The CCA and the utility could mitigate risk associated with forecasts by agreeing in advance that the party who has too much power will explore selling the power to the party who is short on power.

22. In anticipation of the risk that a CCA's cut-over date is delayed, the CCA and the utility may be able to mitigate costs with a reciprocal agreement whereby the party who has too much power will sell it at cost to the party that is short.

23. A Commission order relieving a utility of its duty to procure power for prospective CCA customers after the utility and the CCA have filed a binding notice of intent would unnecessarily add cost and delay to the CCA program.

24. R.04-04-026 is considering the extent to which CCAs must comply with RPS requirements.

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25. The utilities make a convincing case that they will incur costs when new customers are added to the CCA's customer base.

26. Direct access customers currently must provide six months advance notice before returning to the utility as a bundled customer and must make a three-year commitment to taking bundled utility service.

27. Tailoring the utility-CCA service agreement or the binding notice of intent to recognize specific circumstances may improve operational efficiency.

28. D.04-12-46 found the utilities may not charge CCAs for call center services until those costs are unbundled in a general rate case because the utilities are already recovering such costs as part of their revenue requirements.

29. Permitting customers to opt-out of CCA service over the internet may reduce the costs of processing that customer election.

30. Requiring the utilities to provide for a single deposit for the CCA and the utility puts the utility in the position of setting rates for the CCA.

31. Where no need for immediate action is required, there is no justification for requiring the utilities to switch over a customer from the utility to the CCA within days.

32. If a municipality is added to or removed from the CCA, the utility's operations and the CRS could be affected.

33. CCA customers do not require five notices of their option to opt-out of utility service and the costs of a fifth notice, as the utilities propose, would be substantial.

34. The ISO has tariffs that would require certain types of information from and fees for load serving entities, such as CCAs.

35. Private aggregation could affect utility operations in ways that are unexplained by the parties to this proceeding.

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36. The utilities incur costs when they conduct EDI testing.

37. Utilities may incur costs when they provide "special" (non-tariffed) services to CCAs.

38. PG&E's proposed meter data management agent meter (MDMA) data posting fee includes the cost of software and physical meter reading.

39. The utilities' proposed tariff provisions regarding their right to terminate CCA service without the consent of the CCA are vague and provide the utilities with too much discretion.

40. D.04-12-046 required the utilities to unbundle billing services. PG&E has not proposed an unbundled billing service that would permit CCAs to provide adequate information to customers about rates. Its proposed rate for billing service is not unbundled.

41. D.04-12-046 required that a utility's general body of customers should assume the costs of system changes required to serve CCAs, consistent with AB 117.

Conclusions of Law

1. AB 117 provides for limited jurisdiction over CCA program implementation. The statute's provisions for participation in the CCA program are generally either permissive as to the CCA or govern the Commission's regulation of the utilities in the way they offer services to the utilities or structure CCA rates so as to protect utility bundled customers.

2. Although relevant portions of AB 117 do not confer general regulatory oversight of CCAs, the Commission has the authority to exercise limited jurisdiction over non-utilities in furtherance of their regulation of public utilities, including resource adequacy. (*See PG&E Corp. v. CPUC,* 118 Cal. App. 4th (2001) 1195-1201.

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3. Commission has authority to subpoena information and witnesses, to require information from a CCA and require its involvement in any relevant Commission inquiry, whenever germane to the Commission's obligations under AB 117.

4. AB 117 does not require the Commission to approve, disapprove, decertify or modify a CCA's implementation plan. AB 117 requires the CCA to file an implementation plan with the Commission and to register with the Commission before initiating electricity service to customers.

5. The Executive Director should implement a process under which disputes between a CCA and a utility may be facilitated or mediated, as required and as set forth herein.

6. The Executive Director should develop and publish instructions for CCAs and utilities that would include a timeline and describe the procedures for submitting and certifying receipt of the CCA's implementation plan, notice to customers, notice to CCAs of the appropriate CRS, and registration of CCAs. The process and timeline should be consistent with AB 117 and this order.

7. Each CCA registration packet should be required to include (1) the CCA's service agreement with the serving utility; and (2) evidence of insurance or a bond that will cover such costs as potential re-entry fees, penalties for failing to meet operational deadlines, and errors in forecasting.

8. The use of the term "fully cooperate" in Section 366.2(c)(9) is reasonably interpreted to mean that utilities shall facilitate the CCA program and a CCA's efforts to implement it to the extent reasonable and in ways that do not compromise other utility services.

9. AB 117 circumscribes the Commission's role in establishing protections for the customers of CCAs.

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10. Utility tariffs are generally not appropriate vehicles for regulating the protections CCAs offer to their customers.

11. AB 117 permits the Commission to order the utilities to include CCA customer notifications in the utility's bills.

12. AB 117 requires that every customer offered service by the CCA be served by the CCA unless the customer affirmatively declines CCA service. The statute does not make exceptions for bundled portfolio service customers, direct access customers or new customers.

13. Utility tariffs should provide that every customer who does not affirmatively decline CCA service shall be served by the CCA, including customers with commodity contracts and customers whose service notification letters are returned unopened.

14. Utilities' ratepayers should not be required to support in rates utility marketing activities related to services to CCA customers.

15. AB 117 requires the CRS include all stranded costs for power originally purchased by the utilities on behalf of CCA customers and does not make exceptions for RPS costs.

16. The CRS should include all stranded utility RPS liabilities originally incurred by the utilities on behalf of CCA customers.

17. The CRS should be calculated yearly and then trued-up for the period two years prior as information about actual utility procurement costs becomes available.

18. The utilities' proposed tariffs should not require that all customers be served by the CCA within a year of the date the CCA first offers service and should charge for these customer service phase-ins according to cost.

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19. The utilities will not procure power on behalf of CCA customers as part of their resource adequacy planning.

20. The utilities' plan to create a voluntary open season and a binding notice of intent that specifies a CCA operational date is reasonable with the conditions set forth herein.

21. The CRS should not be modified to reflect cost liabilities associated with QA contract renewals or modifications negotiated after the initiation of CCA service.

22. The utilities and CCAs should work collaboratively to develop forecasts for load the utilities will lose when a CCA initiates service. Utility tariffs should require that CCA's provide information about services, rates and customer groups on a confidential basis, to facilitate the development of a forecast.

23. A utility should not be permitted to impose risk on the CCA for the utility's own load forecasts once the CCA has initiated service.

24. A collaborative process whereby the utility and the CCA work together to develop a forecast of departing load, would help mitigate forecast risk.

25. For purposes of estimating liability when a CCA's cut-over date is delayed, the utilities should assume default opt-out figures for the forecast of the first year of the CCA's operation of 5% for residential customers and 20% for industrial and commercial customers unless the utility and the CCA agree to other numbers.

26. Because the utility is responsible for its load forecasts, the purpose of this tariff provision should be to estimate cost liability when the CCA's cut-over date is delayed.

27. The CCA and the utility should explore options for mitigating risk associated with forecasts by agreeing in advance that the party who has too

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much power will sell the power to the party who is short on power. Utility tariffs should be required to include a provision whereby the utility offers to explore whether purchasing power from the CCA at cost or at market rates would mitigate risks or cost, in the event the CCA's cut-over date is delayed.

28. Utility tariffs should provide that in the even the CCA delays the cut-over date from that in the binding notice of intent, the incremental costs of delay associated with power purchases are to be charged to the CCA.

29. Utility tariffs should provide that in the event the CCA's cut-over date is delayed due to acts or omissions of the utility, the utility or its ratepayers shall assume the cost of the delay associated with power purchases. The utility should entered related costs into a memorandum account and should not include such costs in rates until and unless it is authorized to do so by the Commission. In the event the utility does not agree to its culpability, the CCA's remedy is to file a formal complaint seeking credit for the costs of delay associated with power purchases. If the CCA seeks damages, its remedy is to file suit in a court of law.

30. A binding notice of intent signed by the CCA and which specifies a date for the CCA's initiation of service, which specifies phase-ins where planned, should automatically relieve the utility of its obligation for purchasing power for the CCA's customers as of the specified service initiation date.

31. Utility tariffs should provide that the CCA's open season information is to remain confidential at the option of the CCA in order to assure the CCA is in a reasonable bargaining position with respect to power sellers.

32. Utility CCA tariffs should not address the extent to which CCAs must comply with RPS standards.

33. The utilities should be permitted to charge the CCASR fee when new customers are added to the CCA's customer base.

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34. AB 117 requires the CCA to notify new customers of their opportunity to opt-out of CCA services.

35. New customers should be automatically assigned to the CCA unless the utility receives an opt-out request. A new utility customer should be referred to the CCA, which would describe the opt-out process.

36. Section 366.2(c)(18) gives authority to the utilities to install, maintain and calibrate metering devices. Permitting third-party vendors to conduct these services would be contrary to the statute.

37. Section 366.2(c)(9) requires the utilities to provide all relevant customer information to CCAs and prospective CCAs and the Commission has found that the statute does not permit the utilities to determine the types of customer information required by CCAs and prospective CCAs. Utility tariffs therefore may not limit access to such information.

38. Section 366.2(c)(11) requires that customers returning from the CCA to the utility be subject to the same terms and conditions appplicable to returning direct access customers. Therefore, utility tariffs should require a six-month advance notification by the customer and a commitment for three years of bundled utility service.

39. Utility tariffs should not include call center fees until they are unbundled from the revenue requirement and otherwise approved in a general rate case consistent with D.04-12-046.

40. Utility tariffs should include fees that reflect the costs of processing a customer who has opted out of CCA service, consistent with AB 117 which requires individual CCAs to assume the costs attributable to their programs.

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41. Utility customer deposits and CCA customer deposits should be determined by the utility and the CCA respectively and should be collected separately.

42. Partial payments should first be applied to services that would be disconnected for non-payment in order to protect customers from disconnection. Remaining payment amounts should be allocated on a pro rata basis between the services of the CCA and the utility that may not be disconnected for non-payment.

43. Utilities should be required to serve a CCA customer that fails to pay for CCA services.

44. Utility tariffs should require the utility to switch over a customer from the utility to the CCA within 15 days.

45. Utility tariffs should anticipate the impacts of a CCA adding or removing a municipality from the CCA's operations. The tariffs should conform this order with regard to the process for filing an implementation plan and should not require more information or procedures than this order requires when the CCA first files the implementation plan.

46. The utilities should not notify customers of their change in service to the CCA, which is the subject of two CCA notices. The utilities may include this information in their regular bill inserts but may not charge CCAs or CCA customers for it.

47. Utility tariffs should not govern the relationships between CCAs and the ISO and utilities should not be permitted to stop serving a CCA on the basis of its relationship with the ISO except by order of the Court, the Commission or the FERC.

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48. Utility CCA tariffs should permit private aggregation to the extent its implementation does not conflict with other utility tariffs following notice by CCA of an intent to offer service.

49. Pursuant to Section 366.2(c)(8), the earliest possible implementation date for the CCA program was the effective date of the tariffs filed pursuant to D.04-12-046 in Phase 1 of this proceeding.

50. The utilities should be ordered to immediately effect the system changes required to satisfy their CCA tariffs following notice by a CCA of an intent to offer service.

51. The earliest possible implementation date for a CCA's provision of service should be the date of the completion of all tariffed requirements but no later than six months following notice by a CCA to offer service or the date the CCA and the utility agree is reasonable, whichever is later, unless an order of the Commission or a letter from the Executive Director states otherwise.

52. Consistent with AB 117 and D.04-12-046, the utilities' tariffs should specify a cost-based charge for EDI testing conducted on behalf of CCAs.

53. Utility tariffs should include charges, based on incremental costs, for special services.

54. The utilities proposed fees for metering services are reasonable except to the extent set forth herein.

55. Utility tariffs should not permit the utility to terminate a CCA's service without the express approval of the CCA unless the utility has an order of a court, the Commission or the FERC. Where continued CCA service would constitute an emergency or may substantially compromise utility operations or service to bundled customers, the utility should seek an emergency order from the Commission. In such cases, the assigned ALJ, in consultation with the

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assigned Commissioner, should be authorized to issue a ruling providing interim authority for the utility to terminate a CCA's service. The utility should also be authorized to serve CCA customers temporarily where the ISO has notified the utility that customers otherwise not be served and following consultation with the CCA, consistent with rules applicable to direct access customers.

56. The utility's cost to notify CCA customers of a lawful termination of CCA service should be charged to the CCA because these are costs that would not be incurred except for the CCA's provision of service.

57. PG&E should be ordered to unbundle its billing services and rates as set forth herein. It should be permitted to charge no more than SCE's rate for "rate ready" billing services until and unless it can demonstrate that its unbundled billing services cost more than that rate.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall file tariffs in compliance with this order no later than 60 days from the effective date of this order.

2. The tariffs filed by PG&E, SDG&E, and SCE in compliance with this order shall be identical to those they submitted in this proceeding and shall not include any provision, language or rate other than the changes required or authorized herein.

3. Utility tariffs shall conform to the rules for an open season as specified in Attachment B of this order.

4. Pursuant to Section 366.2(c)(8), the earliest possible implementation date for the CCA program was the effective date of the tariffs filed pursuant to

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Decision (D.) 04-12-046 in Phase 1 of this proceeding. The utilities shall immediately effect the system changes required to satisfy the tariffs.

5. The earliest possible implementation date for a Community Choice Aggregator's (CCA) provision of service is the date of the completion of all tariffed requirements or the date the CCA and the utility agree is reasonable, whichever is later, unless a Commission order or letter from the Executive Director states otherwise.

6. Utility tariffs shall not permit the utility to terminate a CCA's service without the express approval of the CCA unless the utility has an order of a court, the Commission or the Federal Regulatory Commission. Where continued CCA service would constitute an emergency or may substantially compromise utility operations or service to bundled customers, the utilities shall seek an emergency order from the Commission. In such cases, the assigned administrative law judge (ALJ), in consultation with the assigned Commissioner, is hereby authorized to issue a ruling providing interim authority for the utility to terminate a CCA's service in this or any successor docket.

7. The assigned ALJ shall convene a workshop or other appropriate forum to assure the tariffs filed by the utilities pursuant to Ordering Paragraph 1 are in conformance with this order.

8. In order to facilitate the smooth operation of the CCA where its policies, practices and decisions may affect the utility and its customers, the Executive Director shall develop and publish the steps of an informal process of review, as described herein, that provides a forum for the CCA and the utility to understand the CCA's implementation plans and assures the CCA is able to comply with utility tariffs. The process shall be mandatory at the request of either the utility or the CCA and where the request is presented in writing with a

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recitation of disputed items or areas of concern. The process shall implicate no approvals, either formal or informal, from the Commission. Utility tariffs shall describe the process for resolving disputes over operational issues prior to initiation of services, as set forth herein.

9. Where the CCA fails to conform to approve utility tariffs, the utility shall decline to initiate service to the CCA. If a utility refuses to facilitate the CCA's initiation of service, or declines to provide service to the CCA, it shall inform the Commission and CCA of its reasons in writing. If the CCA believes it or its customers have been improperly refused utility service, whether before a CCA's service is initiated or in a case where the utility interrupts CCA services, the CCA may file a formal complaint with the Commission, which may be litigated or mediated using our usual procedures.

10. The Executive Director shall prepare and publish instructions for CCAs and utilities that includes a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate CRS, and registration of CCAs. The process and the timeline shall be consistent with the statute and with this order. The instructions shall require that the CCA's registration packet include the CCA's service agreement with the underlying utility and evidence of insurance, self-insurance or a bond that will cover such costs as potential re-entry fees, penalties for failing to meet operational deadlines, and errors in forecasting.

11. The ALJ assigned to Rulemaking (R.) 04-03-017 shall initiate consideration of net metering in CCA territories within 60 days of the effective date of this order.

12. The ALJ assigned to this proceeding shall provide an opportunity for parties to comment on whether the Commission should adopt refinements to the

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CCA CRS methodology that are adopted for DA/DL customers in R.02-01-011 or any successor proceeding.

13. This proceeding remains open for the Commission's consideration of implementation issues that may arise prior to the finalization of utility tariffs ordered herein and prior to the initiation of service by the first CCA

This order is effective today.

Dated December 15, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
JOHN A. BOHN
Commissioners

Commissioner Dian M. Grueneich recused herself from this agenda item and was not part of the quorum in its consideration.

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ATTACHMENT A
Page 1 of 5
SUMMARY OF ADOPTED TARIFF ELEMENTS

Section	Utilities' Proposal	CCAs' Proposal	Adopted
III. Commission Jurisdiction Over CCAs and the CCA Program	AB 117 intended that the Commission have authority over the CCA.	AB 117 does not give the Commission jurisdictional authority over the CCA's, but rather, it gives the Commission ministerial responsibilities over the CCAs.	AB 117 does not confer upon the Commission authority over CCAs or their customers.
IV. CCA Implementation Plan and the Process for CCA Registration **(Utility Tariff Section F.)**	The Commission should be able to review this plan, inquire as to its content, and if necessary, disapprove of the plan; an advice letter process and its associated formal review and approval processes should be adopted.	Legislature did not intend for the Commission to assume the close regulatory oversight of CCA operations that the Utilities propose.	AB 117 does not give the Commission discretion to approve or disapprove a CCA implementation plan. The Commission's Executive Director will develop steps for an informal process that will assure that the CCA is able to comply with Utility tariffs.
V. Consumer Protection	The Commission should adopt rules that will enable it to take action if the CCA unexpectedly changes its rates, defrauds customers, or takes part in unauthorized transfer of customers to CCAs, known as "slamming."	The Commission has no jurisdiction over consumer complaints of rates, fraud or "slamming."	The Commission will not provide a forum for negotiating or ruling on disputes between CCAs and their customers; section 394 exempt public agencies from submitting to the Commission's consumer complaint procedures.
VI. 1. Customer Notice **(Utility Tariff Section H. & I.)**	Customer notice should be similar to the noticed required by ESPs.	CCAs' notice should be reviewed and approved by the Commission's public advisor.	Customer notices will be approved by the Commission's Public Advisor; the Utilities shall give the CCAs the option to include these notices in the Utilities' bills.
VI. 2. Customer Notice – Commodity Contracts **(Utility Tariff Section H. & I.)**	Customers with commodity contracts must opt-in to be served by the CCA.	Customers with commodity contracts must opt-out of the CCA program.	Customers with commodity contracts must opt-out of the CCA program.
VI. 3. Customer Notice – Marketing Service **(Utility Tariff Section H. & I.)**		Utilities should not be permitted to market their services.	Utilities shall not market their services to CCA Customers.

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SUMMARY OF ADOPTED TARIFF ELEMENTS

VII. 1. CRS Vintaging	Support CRS vintaging.	Support vintaging the CRS – but oppose the inclusion of additional costs and the inclusion of Renewable Portfolio Standard (RPS) contracts into the CRS calculation.	The CRS shall be vintaged; the Utilities' RPS contract costs shall be included in the CRS calculations; however, resource adequacy costs incurred byt the Utilities after the CCA's cut-over date shall not be included in the CRS calculation.
VII. 2. CRS Vintaging – Phase-ins	Phase-ins should be completed within the first year; otherwise, CCA customers should be responsible for power Utility power liabilities until the completion of the phase-in period.	The Utilities should not be permitted to limit phase-ins.	The phase-in period cannot be limited.
VIII. Open Season	The CCA must make a binding commitment to a five-year forecast of the CCA's load, which can be modified during each year's open season.	Object to the Utilities' proposal; CCSF calls for a cooperative load forecasting process.	A voluntary open season is reasonable. CCA's should disclose the portion of each customer class that is subject to a cut-over and to provide all relevant customer information, subject to a nondisclosure agreement, such as: the number of customers, rate design, special contracts.
IX. Renewable Portfolio Standard	CCAs should be subject to the same requirements as the Utilities.	PU Code Section 387 requires RPS standards to be implemented and enforced by the local governing body of a Public Utility, which should include CCAs.	The CCAs need to identify in their implementation plans how they intend to comply with the RPS requirements. This matter will be resolved in R. 04-04-026
X. 1. Treatment of New Customers	The Utility must generate a CCASR for all customers, otherwise these customers will be assigned to the Utility's bundled service.	New customers should automatically be enrolled as CCA customers and not be subject to CCASR costs.	New customers must be automatically assigned to CCAs and pay for each CCASR, if it is necessary.
X. 2. Boundary Metering **(Utility Tariff Section O.)**	The Utilities should install, maintain and calibrate metering devices.	CCAs' vendors should undertake boundary metering activities.	The Utilities shall install, maintain and calibrate metering devices – not the CCAs' vendors.
X. 3. Customer Information	The Utilities do not need to provide contact and energy usage data for all customers within the CCAs' service territory in advance of the mass enrollment process.		The Utilities must provide to the CCAs all customer and usage data before the CCAs begin offering service.

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SUMMARY OF ADOPTED TARIFF ELEMENTS

X. 4. Customer Switching Rules	Believe that the CCAs' proposal is unlawful.	CCA customers that switch to Utility bundled service should be committed to that service for one year.	CCAs returning to Utility bundled service must make a three-year commitment to the Utility.
X. 5. The Utility-CCA Service Agreement	Do not object to this service agreement.	Do not object to this service agreement.	The draft service agreement appended to the Utilities' tariffs can be tailored by mutual agreement between the Utility and the CCA and will memorialize the CCA's initiation of service.
X. 6. Call Center Fees	CCA customers need to pay these fees whenever they call the Utility seeking information.	Oppose these fees because the Utilities are already reimbursed for such costs.	Call center fees will not be collected from CCA customers at this time; Utilities should address this in general rate cases.
X. 7. Opt-Out Fees	Should be charged (decision is not clear on whether opt-out fee should be charged to the CCA or to the customer wishing not to opt out).	Object to the Utilities' proposal.	CCAs need to pay for the Opt-Out Fees.
X. 8. a. Customer Deposits	CCA customers should pay deposits separately to the CCA.		Each Utility and each CCA needs to collect its own deposit.
X. 8. b. Partial Payment	Partial payments need to first be allocated to pay off services for which customers could be disconnected.	Support prorating partial payments between CCA and Utility service.	Partial payments should first be allocated to paying for dis-connectable services and then, on a prorated basis, to other utility and CCA services.
X. 8. c. Termination of Service	CCAs should not be permitted to return a customer to the Utility for nonpayment.		CCAs may not return a CCA customer for to Utility bundled service for nonpayment of CCA services.
X. 9. CCASR Processing **(Utility Tariff Section M. 11)**	Utilities need a 15 day lead-time to process a switch-over request when matter is not urgent.	Utilities should take three days to process a switch-over.	A 15 day lead-time is appropriate to switch-over a customer.
X. 10. Changing Municipalities in the CCA Plan	The Utilities' tariffs include a detailed description of how the CCA may add/remove a City or County.	The CCAs object to this section of the Utilities tariffs.	The Utilities' tariffs should include a process for recognizing a change in CCA's customer base
X. 11. Confirmation Letters **(Utility Tariff Section I.7)**	Requires that the Utility send a formal notification of customer service, for which it would charge $0.40 per customer, levied on each customer that does not opt-out of the CCA's service.	No Utility notification is required.	This additional notification is not necessary.

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SUMMARY OF ADOPTED TARIFF ELEMENTS

X. 12. Scheduling Coordinator Requirements **(Utility Tariff Section B. 3. c)**	CCA must identify its scheduling coordinator(s) to the ISO.	AB 117 does not require the CCAs to identify their scheduling coordinator(s).	Utility tariffs may not require the CCAs to identify their scheduling coordinator(s).
X. 13. Load Aggregation **(Utility Tariff Section B.8)**	Object to the CCAs' proposal.	Would allow CCA customers to aggregate load without reference to existing tariff restrictions.	Private aggregation is permitted to the extent its implementation does not conflict with Utility tariffs.
X. 14. Notice of Program Implementation	A six month advance notice should be given to the Utility by the first CCA that provides service.	The CCA's service implementation should occur no later than 30 days after the Commission' notice of receipt of the CCA's implementation plan.	Immediate action must be taken by the Utilities in order to make the system changes required once the tariffs are completed or there is a Utility/CCA agreement; prior notice by a CCA is unnecessary.
X. 15. Electronic Data Interchange Testing **(Utility Tariff Section F.5.d)**	CCAs need to pay for EDI testing.	Object to paying for the EDI testing process.	Each CCA needs to pay for EDI testing.
X. 16. Specialized Service Requests **(Utility Tariff Section E.1)**	Supports charging hourly rates for specialized services to a CCA.	Utilities should not charge for services that are not provided to other commodity service providers.	The Utilities can charge for specialized services at cost based rates.
X. 17. Metering Fees	Would charges CCAs $9.28 per interval meter per month.	Object to paying $9.28 per interval meter per month.	CCAs need to pay $9.28 per interval meter per month.
X. 18. Involuntary CCA Service Termination **(Utility Tariff Section T.2**	The costs of notice to customers of termination should be billed to the CCA.		The costs of notice to customers of termination should be billed to the CCA.
X. 18. Involuntary CCA Service Termination **(Utility Tariff Section T.3)**	Utilities should be allowed to terminate a CCA's service for various reasons, including failure to comply with tariff and ISO requirements.	The Utilities should not have authority to terminate CCA service.	The Utilities cannot include language in their tariffs that gives them the discretion to terminate a CCA's service, except in the event of an emergency.
X. 19. Net Metering	Object to the net metering option for CCAs and their customers.		Net metering should be addressed in R. 04-03-017.
X. 20. Rate Ready Billing	PG&E limits CCA's rate structures to two tiers; SDG&E and SCE offer billing service that is not opposed by CCAs.	Object to the PG&E's proposal; prefer an option to elect to have PG&E bill each of the CCA's rates.	PG&E shall develop a billing service that is unbundled, similar to SCE's and SDG&E's respective billing service.

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SUMMARY OF ADOPTED TARIFF ELEMENTS

X. 21. Services Funded By Bundled Rates **(Utility Tariff Section B. 2)**	The language that contains this proposal is unnecessary.	The Utilities should include language in their tariffs that provide CCA services supported by bundled rates until funds/service obligation is transferred to a CCA.	The Utilities must continue to provide tariffed services until the Commission decides otherwise – however, there is no reason to include such language in the Utilities' tariffs.
X. 22. California Alternative Rate of Energy (CARE) Discount	CCA customers should receive the CARE discounts; ratemaking for this policy should be implemented in future rate design proceedings.	Do not object to the Utilities' proposal and believe that the CARE discount should be addressed in each CCA's respective tariff filing.	The Utilities should continue to provide CARE discounts to all qualifying CCA customers.
X. 23. "In-Kind" Power			DWR and interested CCAs can seek reasonable arrangements to take DWR power.
X. 24. Bill Ready Billing	PG&E offers a manual version of this service; SDG&E and SCE offer an automated version of this service.	Objects this service from PG&E because it is too expensive.	PG&E shall develop an automated billing system that is akin to the system implemented by the other two Utilities, within 12 months; PG&E may charge the same rate as SCE charges for this service.

(END OF ATTACHMENT A)

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ATTACHMENT B
Page 1 of 4
Rule [23.2/27.2]
Community Choice Aggregation (CCA) Open Season

Participation in this Rule by a Community Choice Aggregator (CCA) is voluntary. The purpose of this rule is to provide [Utility] with early notice of the planned implementation date of a CCA program.[1]

A CCA may elect to participate in the Open Season, as defined below, for the purpose of mitigating the Cost Responsibility Surcharge (CRS), as designated in Schedule CCA-CRS, that would apply to that CCA's customers absent its participation in the Open Season, and to enable the coordination of resource planning activities of [Utility] and the participating CCA. Nothing in this Rule shall be construed to modify the requirements of Public Utilities Code Section 366.2(d), (e) and (f).

A. CCA Open Season

The CCA Open Season will be from January 1 through [February 15, or March 1 if Load Serving Entity Load Forecast submittals to the California Energy Commission (CEC) are due May 1 or later] of each year.

1. Binding Notice of Intent (BNI)

During the Open Season CCAs will be allowed to submit to the California Public Utilities Commission (Commission) and [Utility], a Binding Notice of Intent (BNI) to serve specified customer classes on a specific date. [Utility] can then rely upon the BNI in making procurement decisions to meet its load and resource adequacy requirements, and enable the coordination of resource planning activities of [Utility] and the CCA submitting the BNI (Participating CCA). The BNI shall indicate, in specific detail, the classes of customers to which the CCA intends to offer service.[2] The BNI shall be self-executing, in that [Utility] may rely on such notice to modify its procurement activities without further action by the Commission. Participating CCAs will be exempt from any CRS related to [Utility] procurement contracts and generation assets acquired after the BNI is submitted. [Utility] will assume liability going forward for those utility procurement and generation obligations assumed after the Participating CCA has provided its BNI. A CCA that elects not to participate in an Open Season

[1] Nonparticipation in this rule by a CCA in no way relieves [Utility] of its obligation to engage in sound resource planning and to cooperate fully with any potential CCA program implementation.

[2] Pub. Util. Code § 366.2(b) requires CCAs to offer service to all residential customers within its jurisdiction.

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Rule [23.2/27.2]
Community Choice Aggregation (CCA) Open Season

assumes liability for net unavoidable utility and Department of Water Resources procurement and generation obligations that were in place until the time the CCA began its operations.

The specified date will refer to the first day that the CCA assumes responsibility for the purchase of the electrical power requirements of CCA customers transferred from Utility service during CCA mass enrollment. By submitting the BNI, the Participating CCA will be bound to accept [Utility] transfer of customers that have not opted-out, subject to provisions in Section B, for electrical power supply services on that date, which will be the first day of the CCA mass enrollment period. The CCA will develop, in consultation with [Utility], a load forecast for the year it intends to commence service, as described in Section 3 below. Participating CCAs assume responsibility for the planning and purchase of its customers' electrical power requirements as provided for in the CCA load forecast. The load forecast will be used to enable the coordination of resource planning activities of [Utility] and the CCA.

2. CCA Forecast

Each Participating CCA shall meet and confer with [Utility] upon submission of its BNI to develop a Load Forecast for the CCA for the year it commits to commence service. To the greatest extent possible the Participating CCA and [Utility] shall collaborate in developing this load forecast by providing the following information: the CCA's description of the customer classes or subsets of the customer classes to which it intends to offer service; a description of the terms and conditions of CCA service; CCA/[Utility] rate forecasts for the year the CCA commences service, [Utility] estimates of bundled customers who do not qualify for CCA mass enrollment including [Utility] updates on near-term efforts to promote programs that would increase this category of customers; and information either the CCA or [Utility] has received regarding customer intent to opt-out of the CCA program. This CCA Load Forecast will be used to adjust [Utility's] bundled load forecast for submittal to the Commission in its Long Term Procurement Plan and to the CEC by [Date to be determined in R.04-04-003] of each year, for resource adequacy verification. The CCA Forecast will be considered final on the date submitted to the CEC, subject to modifications described below in Section B, Adjustments to Forecasts. Such forecast must include the same information and be provided in the same format as required by the CEC or the Commission in accordance with the requirements established for the resource adequacy and integrated energy policy report filings. The CCA Forecast must include the forecast number of customers by rate class that the CCA expects to serve. Unless the CCA and [Utility] otherwise agree, the CCA Load Forecast shall be based on the default assumptions regarding the percentage of customers in the various classes that may opt out of CCA service established by the Commission.

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Rule [23.2/27.2]
Community Choice Aggregation (CCA) Open Season

3. CCA Default on Binding Notice of Intent

   If the CCA fails to commence service on the date stated in the Binding Notice of Intent, or fails to offer service in good faith to all classes of customers stated in that Notice, the CCA will be required to reimburse [Utility], upon demonstration in a filing with the Commission, for any incremental costs associated with utility procurement, as described in Section 6 below, resource adequacy penalties, or any other utility costs that are incurred as a result of CCA's default. However, the CCA or its customers will not be subject to any costs incurred by the Utility as a result of the CCA's failure to commence service on the date specified if the reason for that non-performance relates to a failure of the utility to meet its commitments to the CCA.

4. Potential Penalties for Deviating From CCA Binding Notice of Intent

   If the CCA fails to meet its commencement of service date or fails to offer service in good faith to all customer classes stated in the Notice of Intent, [Utility] shall make a filing with the Commission detailing the incremental costs it incurred as a result of the CCA's failure to fulfill its commitment, for Commission determination of a CCA penalty. The potential penalty to the CCA shall not exceed the would-be transferred load that [Utility] must continue to serve times the difference between [Utility]'s incremental per/kWh cost of acquiring the energy and capacity to serve the load not served by the CCA, and the average cost of [Utility]'s procurement portfolio. This penalty will be calculated on a per day basis for every day that the CCA deviates from the date provided in its Binding Notice of Intent. The CCA shall not be entitled to a credit if [Utility]'s per/kWh cost of serving the load not served by the CCA is below the average cost of [Utility]'s procurement portfolio.

B. Adjustments to Forecasts

In a subsequent Open Season that takes place prior to the CCA commencing service to its customers, the Participating CCA may update its service commencement date. To the extent the CCA and [Utility] have collaborated on the load forecast as described above, the CCA and [Utility] shall provide updates to load forecasting data, such as projected rate or service changes, as they become available in advance of the CCA commencement date. This data shall be used solely to refine the collaborative load forecast when necessary. The CEC may also make adjustments to the CCA's Forecast as part of its review of all Load Serving Entity forecasts in the resource adequacy process. The CCA must satisfy [Utility] credit worthiness standards (which may include provision of adequate security or other assurance) to cover the amount of any potential penalties.

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Rule [23.2/27.2]
Community Choice Aggregation (CCA) Open Season

C. Open Season Phase-In Requirements

In the event a CCA elects to phase-in its service and participate in the Open Season, the CCA shall provide in its Binding Notice of Intent the schedule by which it intends to phase-in service. The CCA shall be required to accept the transfer of customers on the dates provided for each phase of its implementation unless it provides an adjustment in a subsequent Open Season period. The CCA load forecast shall reflect the incremental changes in CCA load as a result of phasing implementation. All other provisions of the Open Season tariff, including penalties for default and confidentiality, apply to participating CCAs that elect to phase-in implementation.

D. CCA Open Season Participation Confidentiality

Due to both the binding nature of the CCA commitment to serve customers on a specified date and the potential penalties a CCA may incur if it fails to fulfill its responsibility to prepare for timely commencement of service under this tariff, there is a potential to create market power for suppliers responding to a CCA's solicitation to provide electric power services. In order to prevent the possibility that participation in this tariff may create market power for potential CCA suppliers, all information concerning CCA participation in this tariff will be confidential. Use of information provided by either the CCA or [Utility] for purposes of load forecasting shall be limited solely for the purposes of the collaborative load forecast. Access to load forecasting information shall be restricted to authorized CCA/[Utility] staff assigned to prepare the load forecasts for submission to the CEC, and the Commission and CEC staff assigned to review such forecasts.

(END OF ATTACHMENT B)

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AB 117
Public Utilities Code

366.2. (a) (1) Customers shall be entitled to aggregate their electric loads as members of their local community with community choice aggregators.

(2) Customers may aggregate their loads through a public process with community choice aggregators, if each customer is given an opportunity to opt out of their community's aggregation program.

(3) If a customer opts out of a community choice aggregator's program, or has no community choice program available, that customer shall have the right to continue to be served by the existing electrical corporation or its successor in interest.

(b) If a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction.

(c) (1) Notwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts. However, the community choice aggregator may not aggregate electrical load if that load is served by a local publicly owned electric utility, as defined in subdivision (d) of Section 9604. A community choice aggregator may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers. The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services. Those service agreements may be entered into by a single city or county, a city and county, or by a group of cities, cities and counties, or counties.

(2) Under community choice aggregation, customer participation may not require a positive written declaration, but all customers shall be informed of their right to opt out of the community choice aggregation program. If no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program.

(3) A community choice aggregator establishing electrical load aggregation pursuant to this section shall develop an implementation plan detailing the process and consequences of aggregation. The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing. The implementation plan shall contain all of the following:

(A) An organizational structure of the program, its operations, and its funding.

(B) Ratesetting and other costs to participants.

(C) Provisions for disclosure and due process in setting rates and allocating costs among participants.

(D) The methods for entering and terminating agreements with other entities.

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ATTACHMENT C

ASSEMBLY BILL 117
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(E) The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.

(F) Termination of the program.

(G) A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

(4) A community choice aggregator establishing electrical load aggregation shall prepare a statement of intent with the implementation plan. Any community choice load aggregation established pursuant to this section shall provide for the following:

(A) Universal access.

(B) Reliability.

(C) Equitable treatment of all classes of customers.

(D) Any requirements established by state law or by the commission concerning aggregated service.

(5) In order to determine the cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs, the community choice aggregator shall file the implementation plan with the commission, and any other information requested by the commission that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f).

(6) The commission shall notify any electrical corporation serving the customers proposed for aggregation that an implementation plan initiating community choice aggregation has been filed, within 10 days of the filing.

(7) Within 90 days after the community choice aggregator establishing load aggregation files its implementation plan, the commission shall certify that it has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism. After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs as provided for in subdivisions (d), (e), and (f).

(8) No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers within its boundaries until the commission determines the cost-recovery that must be paid by the customers of that proposed community choice aggregation program, as provided for in subdivisions (d), (e), and (f). The commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.

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(9) All electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission. Electrical corporations shall continue to provide all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs. Bills sent by the electrical corporation to retail customers shall identify the community choice aggregator as providing the electrical energy component of the bill. The commission shall determine the terms and conditions under which the electrical corporation provides services to community choice aggregators and retail customers.

(10) (A) A city, county, or city and county that elects to implement a community choice aggregation program within its jurisdiction pursuant to this chapter shall do so by ordinance.

(B) Two or more cities, counties, or cities and counties may participate as a group in a community choice aggregation pursuant to this chapter, through a joint powers agency established pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code, if each entity adopts an ordinance pursuant to subparagraph (A).

(11) Following adoption of aggregation through the ordinance described in paragraph (10), the program shall allow any retail customer to opt out and to continue to be served as a bundled service customer by the existing electrical corporation, or its successor in interest. Delivery services shall be provided at the same rates, terms, and conditions, as approved by the commission, for community choice aggregation customers and customers that have entered into a direct transaction where applicable, as determined by the commission. Once enrolled in the aggregated entity, any ratepayer that chooses to opt out within 60 days or two billing cycles of the date of enrollment may do so without penalty and shall be entitled to receive default service pursuant to paragraph (3) of subdivision (a). Customers that return to the electrical corporation for procurement services shall be subject to the same terms and conditions as are applicable to other returning direct access customers from the same class, as determined by the commission, as authorized by the commission pursuant to this code or any other provision of law. Any reentry fees to be imposed after the opt-out period specified in this paragraph, shall be approved by the commission and shall reflect the cost of reentry. The commission shall exclude any amounts previously determined and paid pursuant to subdivisions (d), (e), and (f) from the cost of reentry.

(12) Nothing in this section shall be construed as authorizing any city or any community choice retail load aggregator to restrict the ability of retail electricity customers to obtain or receive service from any authorized electric service provider in a manner consistent with law.

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(13) (A) The community choice aggregator shall fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment. Notifications may occur concurrently with billing cycles. Following enrollment, the aggregated entity shall fully inform participating customers for not less than two consecutive billing cycles. Notification may include, but is not limited to, direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:

(i) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty.

(ii) The terms and conditions of the services offered.

(B) The community choice aggregator may request the commission to approve and order the electrical corporation to provide the notification required in subparagraph (A). If the commission orders the electrical corporation to send one or more of the notifications required pursuant to subparagraph (A) in the electrical corporation's normally scheduled monthly billing process, the electrical corporation shall be entitled to recover from the community choice aggregator all reasonable incremental costs it incurs related to the notification or notifications. The electrical corporation shall fully cooperate with the community choice aggregator in determining the feasibility and costs associated with using the electrical corporation's normally scheduled monthly billing process to provide one or more of the notifications required pursuant to subparagraph (A).

(C) Each notification shall also include a mechanism by which a ratepayer may opt out of community choice aggregated service. The opt out may take the form of a self-addressed return postcard indicating the customer's election to remain with, or return to, electrical energy service provided by the electrical corporation, or another straightforward means by which the customer may elect to derive electrical energy service through the electrical corporation providing service in the area.

(14) The community choice aggregator shall register with the commission, which may require additional information to ensure compliance with basic consumer protection rules and other procedural matters.

(15) Once the community choice aggregator's contract is signed, the community choice aggregator shall notify the applicable electrical corporation that community choice service will commence within 30 days.

(16) Once notified of a community choice aggregator program, the electrical corporation shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process.

(17) An electrical corporation shall recover from the community choice aggregator any costs reasonably attributable to the community choice aggregator, as determined by the commission, of implementing this section, including, but not limited to, all business and information system changes, except for transaction-based costs as described in this paragraph. Any costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers, as determined by the commission. All reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers shall be recovered from the aggregator or its customers on terms

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and at rates to be approved by the commission.

(18) At the request and expense of any community choice aggregator, electrical corporations shall install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the community aggregator's political boundaries. The electrical corporation shall read the metering devices and provide the data collected to the community aggregator at the aggregator's expense. To the extent that the community aggregator requests a metering location that would require alteration or modification of a circuit, the electrical corporation shall only be required to alter or modify a circuit if such alteration or modification does not compromise the safety, reliability or operational flexibility of the electrical corporation's facilities. All costs incurred to modify circuits pursuant to this paragraph, shall be born by the community aggregator.

(d) (1) It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources' electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.

(2) The Legislature finds and declares that this subdivision is consistent with the requirements of Division 27 (commencing with Section 80000) of the Water Code and Section 360.5, and is therefore declaratory of existing law.

(e) A retail end-use customer that purchases electricity from a community choice aggregator pursuant to this section shall pay both of the following:

(1) A charge equivalent to the charges that would otherwise be imposed on the customer by the commission to recover bond related costs pursuant to any agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, which charge shall be payable until any obligations of the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code are fully paid or otherwise discharged.

(2) Any additional costs of the Department of Water Resources, equal to the customer's proportionate share of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the Department of Water Resources.

(f) A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:

(1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.

(2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with

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the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

(g) (1) Any charges imposed pursuant to subdivision (e) shall be the property of the Department of Water Resources. Any charges imposed pursuant to subdivision (f) shall be the property of the electrical corporation. The commission shall establish mechanisms, including agreements with, or orders with respect to, electrical corporations necessary to ensure that charges payable pursuant to this section shall be promptly remitted to the party entitled to payment.

(2) Charges imposed pursuant to subdivisions (d), (e), and (f) shall be nonbypassable.

(h) Notwithstanding Section 80110 of the Water Code, the commission shall authorize community choice aggregation only if the commission imposes a cost-recovery mechanism pursuant to subdivisions (d), (e), (f), and (g). Except as provided by this subdivision, this section shall not alter the suspension by the commission of direct purchases of electricity from alternate providers other than by community choice aggregators, pursuant to Section 80110 of the Water Code.

(i) (1) The commission shall not authorize community choice aggregation until it implements a cost-recovery mechanism, consistent with subdivisions (d), (e), and (f), that is applicable to customers that elected to purchase electricity from an alternate provider between February 1, 2001, and January 1, 2003.

(2) The commission shall not authorize community choice aggregation until it submits a report certifying compliance with paragraph (1) to the Senate Energy, Utilities and Communications Committee, or its successor, and the Assembly Committee on Utilities and Commerce, or its successor.

(3) The commission shall not authorize community choice aggregation until it has adopted rules for implementing community choice aggregation.

(j) The commission shall prepare and submit to the Legislature, on or before January 1, 2006, a report regarding the number of community choices aggregations, the number of customers served by community choice aggregations, third party suppliers to community choice aggregations, compliance with this section, and the overall effectiveness of community choice aggregation programs.

(END OF ATTACHMENT C)

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ATTACHMENT D

COMMUNITY CHOICE AGGREGATION PROGRAM IMPLEMENTATION PLAN

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Below is a description of the sequence of steps that will be taken by the CCA, and the California Public Utilities Commission, in the CCA implementation process. Note the day that the CCA files its implementation plan will demark "day one" of the implementation process. Parties should also note when submitting their implementation plan that the Open Season will be held from January 1st through February 15th of each year; if the Load Serving Entity's forecast submittal to the California Energy Commission is due on May 1st or later, the Open Season will be extended to March 1st.

DAY 1:

(1) The CCA is to submit two copies of its implementation plan to the CPUC's Energy Division, in addition to servicing a notice on all parties to the R.03-10-003 service list.

DAY 1 – 10:

(1) The CPUC will notify the Utility servicing the customers that are proposed for aggregation that an implementation plan initiating their CCA program has been filed. (P.U. Code Section 366.2 (c) (6))

DAY 1 – 60:

(1) CCA is to provide a draft customer notice to CPUC's Public advisor.

(2) Within **15 days** of the CCA providing a draft notice to the CPUC's Public Advisor, the Public Advisor shall finalize the CCA notice.

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COMMUNITY CHOICE AGGREGATION PROGRAM IMPLEMENTATION PLAN

DAY 1 – 90:

(1) The CPUC will certify that it has received the implementation plan, including any additional information that the CPUC deems necessary in order to determine a cost-recovery mechanism. (P.U. Code Section 366.2 (c) (7))

   a. If and when the CPUC requests additional information from a CCA, the CCA shall respond to the staff within **10 days**, or notify the staff of a date when the information will be available.

(2) The CPUC will provide the CCA with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (P.U. Code Section 366.2 (c) (7))

(3) The CCA and the Utility may engage in a facilitation process with regards to the CCA's ability to conform its operations to the Utility's tariff requirements.

WITHIN 60 DAYS OF THE CCA'S COMMENCEMENT OF ITS AUTOMATIC CUSTOMER ENROLLMENT:

(1) The CCA shall send its first notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A))[1]

[1] The CCA may request that the CPUC approve and order the Utility to send one or more of the notifications called for in P.U. Code Section 366.2 (c) (A) in the Utility's normally scheduled monthly billing process. The Utility would be entitled to recover from the CCA all reasonable incremental costs it incurs related to the notification(s). (P.U. Code Section 366.2 (c) (B)).

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COMMUNITY CHOICE AGGREGATION PROGRAM
IMPLEMENTATION PLAN
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WITHIN 30 DAYS OF THE CCA'S AUTOMATIC CUSTOMER ENROLLMENT:

(1) The CCA shall send a second notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A))

(2) The CPUC will send a letter to the CCA, copied to serving Utility, notifying it that it has been registered as a CCA. (P.U. Code Section 366.2 (c) (13) (A))

(3) Once the CCA contract is signed, the CCA shall notify the applicable Utility that CCA service will commence within 30 days. (P.U. Code Section 366.2 (c) (15))

(4) Once notified of a CCA program, the Utility shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process. (P.U. Code Section 366.2 (c) (16))

FOLLOWING THE CCA'S AUTOMATIC CUSTOMER ENROLLMENT:

(1) The CCA shall inform participating customers for no less than two consecutive billing cycles that:

a. They have been automatically enrolled into the CCA program and that each customer has the right to opt out of the CCA program without penalty. (P.U. Code Section 366.2 (c) (13)(A)(i))

b. Terms and conditions of the services being offered. (P.U. Code Section 366.2 (c) (13)(A)(ii))

(END APPENDIX D)

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APPENDIX A
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(END OF APPENDIX A)

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EXHIBIT 2

Resolution E-4017, Approval of a Citation Program Authorizing Commission Staff to Enforce Compliance with System and Local Resource Adequacy Filing Requirements by Load-Serving Entities Within the Service Territories of California's Three Largest Investor-Owned Electric Utilities

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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Energy Division **San Francisco, California**
Date : October 5, 2006
Resolution No. E-4017

R E S O L U T I O N

RESOLUTION E-4017. Approval of a citation program authorizing Commission Staff to enforce compliance with system and local resource adequacy filing requirements by load-serving entities within the service territories of California's three largest investor-owned electric utilities.

SUMMARY

This Resolution approves a citation program under the administration of the Director of the Energy Division for enforcing compliance with certain system and local resource adequacy filing requirements that apply to all load-serving entities ("LSEs")[1] in the service territories of California's three largest investor-owned utilities. Specifically, the citation program will enforce compliance with the requirements for submission of load data and forecasts, other resource adequacy compliance filings, and responses to requests for information by Energy Division or the California Energy Commission ("CEC") reasonably related to the implementation of resource adequacy requirements. Staff will be delegated authority to draft and issue citations for specific violations and levy penalties in specified amounts as set forth in Appendix A. The penalties may be levied for: (1) failure to submit the load data, forecasts and other compliance filings in the time or manner required; and (2) failure to otherwise provide information reasonably related to the implementation of resource adequacy requirements requested by Energy Division or the CEC in the time and manner required.

Delegation of authority to Energy Division will allow prompt action by Staff to protect the public and fulfill the objectives of the Commission's resource adequacy program and Public Utilities Code section 380 (Section 3 of Stats. 2005,

[1] LSEs include investor owned utilities, electric service providers and community choice aggregators.

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Ch. 367 (A.B. 380)).[2] This Resolution is based on the authority vested in the Commission by: the California Constitution; California statutes and court decisions; and prior Commission decisions and orders. Nothing in this Resolution diminishes, alters, or reduces the Commission's existing authority to promote and enforce public safety and the reliability of California's electricity supply.

BACKGROUND

Beginning in 2004, the Commission issued a series of decisions on resource adequacy to ensure adequate, cost-effective investment in electric generation capacity for California and that such capacity is available to the California Independent System Operator ("CAISO") to reliably serve California's growing demand for electricity.[3]

The resource adequacy requirements are comprehensive, and require demonstrations of both: (1) aggregate or system resource adequacy (acquisition of sufficient generation capacity to serve forecasted retail customer load plus a reserve margin without accounting for local transmission constraints); and (2) local resource adequacy (acquisition of sufficient generation capacity within defined, transmission-constrained areas).[4] There currently are a number of required compliance filings:

- **"**Historic Load Data": actual load data from the prior year submitted to the CEC.

- **"**Preliminary Load Forecast": an annual, year-ahead hourly load forecast for all twelve months of the following year submitted to Energy Division.

- "Preliminary Local RAR Compliance Filing": an advice letter filing with Energy Division using an approved template that demonstrates the LSE's capacity contracts for 2007 with units included on the *2007 Local Area Resource Data List* maintained by the CAISO for proposed 2007 RMR contracts.

- **"**Year-Ahead System Resource Adequacy Compliance Filing**":** an annual advice letter filing with Energy Division using an approved template that

[2] Unless otherwise noted, all statutory references are to the Public Utilities Code.
[3] *Policy and Program Coordination in Electric Utility Resource Planning (First Interim Opinion)* [D.04-01-050] (2004) ___ Cal.P.U.C.3d ___; *Policy and Program Coordination in Electric Utility Resource Planning (Resource Adequacy Opinion)* [D.04-10-035] (2004) ___ Cal.P.U.C.3d ___; *Opinion on Resource Adequacy Requirements* [D.05-10-042] (2005); *Opinion on Local Resource Adequacy Requirements* [D.06-06-064] (2006).
[4] D.05-10-042, at pp. 82-92; D.06-06-064.

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demonstrates qualifying capacity contracts in sufficient megawatt quantities to satisfy the 90% forward commitment obligation for loads plus reserve requirements for each of the five summer months, May – September, of the following year.

- "Year-Ahead Local Resource Adequacy Compliance Filing": an annual advice letter filing with Energy Division using an approved template that demonstrates qualifying capacity contracts in sufficient megawatt quantities to satisfy100% of the local procurement obligation for each month of the next calendar year (January through December).

.

- **"**Month-Ahead System Resource Adequacy Compliance Filings**":** (1) a monthly advice letter filing with Energy Division using an approved template which demonstrates: (a) acquisition of 100% of the qualifying system capacity obligation (adjusted forecast plus reserve margin) for a "compliance month" from the qualifying capacity providers maintained by the CAISO and the amount of capacity from each provider; and (b) the sale of any qualifying capacity previously identified in a resource adequacy compliance filing for system resource adequacy requirements, and that the capacity remains fully available to the CAISO; and (2) a monthly load forecast submitted to the CEC demonstrating adjustments to the Preliminary Load Forecast for positive and negative load growth due to load migration.

Energy Division is authorized to revise the required content of the compliance filing templates and guides as necessary for orderly implementation of the resource adequacy program.[5]

In January 2006, the Legislature enacted section 380, which directs the Commission to exercise its enforcement powers to ensure compliance with resource adequacy requirements, to enforce resource adequacy requirements in a non-discriminatory manner, and to minimize enforcement requirements and costs.[6] Section 380(f) requires the Commission to obtain sufficient information to enable the Commission to determine compliance with the resource adequacy requirements established by the Commission. Section 380 also empowers the Commission to determine and authorize the "most efficient and equitable means" to achieve the objectives of the statute.[7]

[5] D.06-06-064, mimeo at p. 88, Conclusion of Law 30(c).
[6] Sections 380(b) (3) & (e).
[7] Section 380(h).

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DISCUSSION

Under section 380, the Commission has a statutory mandate and broad powers to enforce compliance with resource adequacy requirements. In addition, pursuant to section 2101, the Commission has the power to act as an enforcement agency and to ensure that penalties are promptly prosecuted and collected. Public utilities are subject to enforcement action and penalties pursuant to sections 2102-2105, 2107, 2108 and 2114. Electric service providers are subject to enforcement action pursuant to these same code sections as if they were public utilities.[8] Community choice aggregators are subject to enforcement action pursuant to section 2111.

California law, including section 7 of the Public Utilities Code, allows delegation of powers by the Commission.[9] The Commission may delegate to its Staff the performance of certain functions, including investigation of facts preliminary to agency action, and the assessment of specific penalties for certain types of violations.[10]

A citation program administered by Staff for specified violations of the Commission's resource adequacy requirements will allow prompt action by Staff to protect consumers, minimize enforcement costs, and fulfill the objectives of the Commission's resource adequacy program and section 380. This citation program is consistent with other approved citation programs. For example, the types of violations that Staff may enforce by citation and the citation procedures are substantially similar to those approved in General Order No. 167 for the citation program administered by Staff for the operation and maintenance standards for electric generation facilities.[11] The amounts of the proposed penalties also are similar to those approved in General Order No. 167. The penalty for failure to file the Year-Ahead Local Resource Adequacy filing, which was specifically determined in D.06-06-064, will not be the subject of this citation program, but will be enforced through formal Commission proceedings.[12]

The issuance of a citation for a specified violation is not mandatory. In enforcing compliance with Resource Adequacy filing requirements, or in response to any Specified Violation, the Commission may initiate any authorized formal proceeding or pursue any other remedy authorized by the California Constitution, the Public Utilities Code, other state or federal statutes, court decisions or decrees, or otherwise by law or in equity. Finally, the Commission's enforcement of this

[8] Section 394.25.
[9] D.06-01-047, mimeo at pp. 9-12.
[10] *Id.*
[11] *See also* Resolution ALJ-187, September 22, 2005.
[12] D.06-06-064, mimeo at pp. 69-70 and p. 87, Conclusion of Law 26.

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Resolution by informal proceedings, formal proceedings, or otherwise, does not bar or affect the remedies otherwise available to other persons or government agencies.

PROPOSED CITATION PROGRAM

1.0 Specified Violations and Scheduled Penalties

1.1 "Specified Violation" means the failure, absent an approved extension, to submit: (a) any load data, load forecast or other resource adequacy compliance filing in the time and manner required; and (b) other information requested by Energy Division or the CEC that is reasonably related to the implementation of resource adequacy requirements. Appendix A sets forth the Specified Violations.

1.2 "Scheduled Penalties" for Specified Violations are set forth in Appendix A.

1.3 Modification of Appendix A. The Commission may modify Appendix A no earlier than thirty (30) days after providing reasonable notice and affording interested persons with an opportunity to comment.

2.0 Procedures for Citation Program

2.1 Citations for Specified Violations. After appropriate informal investigation and verification that a Specified Violation defined in this Resolution has occurred, the Director of the Energy Division or his/her designee is authorized to issue a citation. The Specified Violations and the corresponding Scheduled Penalty that may be levied are described in Appendix A to this Resolution.

2.2 Service of Citations. Citations shall be sent by the Director of Energy Division or his/her designee by first class mail to the Respondent, the LSE to which a citation has been issued pursuant to this Resolution, at the address of the agent for service of process.

2.3 Content of Citations. Citations shall state the alleged violation, the evidence supporting the alleged violation, and the proposed Scheduled Penalty. The citation may summarize the evidence and Energy Division shall make the evidence available for timely inspection upon request by the Respondent. Citations also shall include an explanation of how to file an appeal of the citation, including the explanation of a right to have a hearing, to have a representative present at the hearing, and to request a transcript.

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2.4 Response to Citation. A Respondent may either: (1) accept the citation and the Scheduled Penalty; or (2) appeal the citation.

2.5 Filing with Energy Division. Unless otherwise specified, "notify Energy Division," "filing," or "file" means to send a written communication by the U.S. Mail or an express mail service to Energy Division, 4th Floor, Attn: RAR Filing, 505 Van Ness Avenue, San Francisco, CA 94102. These written communications are not filed with the Commission's Docket Office. In addition to or instead of communications by mail service, Energy Division may allow electronic submissions.

2.6 Acceptance of Scheduled Penalty. In the event the proposed Scheduled Penalty is accepted, the Respondent shall notify Energy Division in writing within thirty (30) days of the date of the citation, and shall pay the penalty in full as set forth in subsection 2.8, below.

2.7 Appeal of Citation. In lieu of accepting the Scheduled Penalty, a Respondent may appeal the citation and request a hearing. In the event of an appeal, any remedy available may be imposed, and the remedy shall not be mandated by or limited to the Scheduled Penalty.

2.7. 1. Notice of Appeal. To appeal a citation, the Respondent must file a written Notice of Appeal. The Notice of Appeal must state the grounds for appeal and be filed with Energy Division within thirty (30) days of the date of the citation.

2.7.2. Referral to Administrative Law Judge. Upon receipt of a timely Notice of Appeal, Energy Division shall promptly provide a copy of the Notice of Appeal to the Chief Administrative Law Judge. The Chief Administrative Law Judge shall promptly designate an Administrative Law Judge to hear the appeal.

2.7.3 Time of Hearing. No less than ten (10) days after the Notice of Appeal is filed, the assigned Administrative Law Judge shall set the matter for hearing promptly. The Administrative Law Judge, may, for good cause shown or upon agreement of the parties, grant a reasonable continuance of the hearing.

2.7.4 Location of Hearing. Appeals of citations shall be heard in the Commission's San Francisco courtroom on regularly scheduled days.

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2.7.5 Transcripts. The Respondent may order a transcript of the hearing, and shall pay the cost of the transcript in accordance with the Commission's specified procedures.

2.7.6 Representation at Hearing. The Respondent may be represented at the hearing by an attorney or other representative, but any such representation shall be at the Respondent's expense.

2.7.7. Evidentiary Hearing. At an evidentiary hearing, Energy Division bears the burden of proof and, accordingly, shall open and close. The Administrative Law Judge may, in his or her discretion to better ascertain the truth, alter the order of presentation. Formal rules of evidence do not necessarily apply, and all relevant and reliable evidence may be received at the discretion of the Administrative Law Judge.

2.7.8 Submission. Ordinarily, the matter shall be submitted at the close of the hearing. The Administrative Law Judge, upon a showing of good cause, may keep the record open for a reasonable period to permit a party to submit additional evidence or argument.

2.7.9 Decision. The Administrative Law Judge shall issue a draft resolution resolving the appeal not later than thirty (30) days after the appeal is submitted in accordance with subsection 2.7.8, and the draft resolution shall be placed on the first available agenda, consistent with the Commission's applicable rules.

2.7.10 Communications. From the date that a citation is issued to and including the date when the final decision is issued, neither the Respondent nor Energy Division, or any agent or other person on behalf of the Respondent or Energy Division, may communicate regarding the appeal, orally or in writing, with a Commissioner, Commissioner's advisor, or Administrative Law Judge, except as expressly permitted under these procedures.

2.8 Payment of Scheduled Penalties. Payment of Scheduled Penalties shall be submitted to the Commission's Fiscal Office, 505 Van Ness Avenue, San Francisco, CA 94102, in the form of certified check, payable to the State Treasury for the credit of the State General Fund.

2.9 Default. If the Respondent: (a) notifies Energy Division of acceptance of a Scheduled Penalty and fails to pay the full amount of the Scheduled Penalty within thirty (30) days of the date of the written acceptance of the Scheduled Penalty; or (b) fails to notify Energy Division of acceptance of a

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Scheduled Penalty or fails to file a written Notice of Appeal in the manner and time required, then the citation and penalty shall become final and the Respondent is in default. Upon default, any unpaid balance of a Scheduled Penalty shall accrue interest at the legal rate of interest for judgments, and Energy Division and the Commission may take any action provided by law to recover unpaid penalties and ensure compliance with applicable statutes and Commission orders, decisions, rules, directions, demands or requirements.

2.10 Reporting. Energy Division shall regularly report to the Commission after taking action pursuant to this Resolution. The report shall include a summary of the citations and penalties imposed, penalties paid, and the disposition of any appeals.

COMMENTS

The Draft Resolution was mailed to the parties in interest on August 21, 2006, in accordance with Public Utilities Code section 311(g) (1) and Rule 77.7 of the Rules of Practice and Procedure.

The Commission received and reviewed comments submitted by Southern California Edison ("SCE") and the Alliance for Energy Markets ("AReM") on September 5, 2006. Reply comments were received from Pacific Gas and Electric Company ("PG&E"), Sempra Energy ("SDG&E"), and AReM on September 11, 2006. While we do not attempt to summarize and respond to all comments here, we have carefully considered the comments of all parties, and respond to a few particular concerns here for clarification.

SCE suggests that the Commission modify Resolution E-4017 to explicitly authorize a cure period of ten days before a citation can be issued for a Specified Violation. Similarly, AReM requests that the Resolution provide for a three day grace period for all covered filings and submissions. SCE argues that the concept of a grace or cure period is consistent with our previous decisions in the Local Resource Adequacy proceeding (R.05-12-013), including D.06-06-064.

A related comment is SCE's position that in D.06-06-064, the scheduled penalty for failure to submit a Year-Ahead Local Resource Adequacy Compliance Filing was meant to be based on the amount the LSE is deficient, not the LSE's entire Local RA obligation. SCE further argues that calculating penalties using the $40/kW-year amount based on the LSE's entire Local RA obligation could result in the assessment of a penalty in excess of the statutory limit in Public Utilities Code 2107 and 2111.

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We disagree with SCE's interpretation of D.06-06-064, and decline to adopt SCE and AReM's suggestions, for the following reasons. D.06-06-064 allows, but does not mandate a grace period of *up to* ten calendar days for failure to make its monthly Local RAR filing. However, if we were to include a grace period for all LSE compliance filings in the Resolution itself, this would encourage filings beyond the deadline but within the grace period, thereby effectively moving back the deadline. As we observed in D.06-06-064, "time is of the essence with respect to LSE compliance filings."

We further explained that the failure to make timely monthly Local RAR compliance filings could result in the CAISO procuring backstop resources for the LSE's entire Local RAR obligation, as there would be no filing to confirm whether the LSE was only partially deficient, or had not procured any of its load at all. Within this context, we concluded that "the penalty for failure to make a timely compliance filing should, after a grace period not to exceed 10 calendar days, be equal the penalty for a deficiency." (D.06-06-064 at pp. 68-69.)

We believe that SCE's concerns regarding the amount of the potential penalties for failure to file the Year-Ahead Local Resource Adequacy Compliance filing have been adequately addressed in D.06-06-064, where we noted that our enforcement efforts will be consistent with the penalty regime established in D.05-10-042, which fully comports with statutorily authorized penalties. (See D.06-06-064, p. 67, fn. 19.) We are persuaded, however, that this penalty should not be the subject of a staff citation program, but rather, is more appropriate for enforcement through the Commission's formal enforcement proceedings, such as an Order to Show Cause or Order Instituting Investigation. Therefore, we have removed the penalty for Failure to submit a Year-Ahead Local Resource Adequacy Compliance filing from the Specified Violations listed in Appendix A of this Resolution.

AReM raises concerns over the confidentiality of the citation program, arguing that the identity of the LSE and contents of any citation be confidential until a final resolution of the matter is reached. The Commission has an ongoing proceeding for determining confidentiality of electric procurement data in R.05-06-040, and we think confidentiality issues are best addressed using the guidelines established in D.06-06-066, and other authority.

AReM points out that there is an incorrect statutory reference to Public Utilities Code section 2017, which should be Public Utilities Code 2107. This has been corrected in the Resolution.

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FINDINGS OF FACT:

1. D.04-10-035, D.05-10-42 and D.06-06-064 require the submission of load data, load forecasts and other compliance filings by LSEs within the service territories of California's three largest investor-owned electric utilities: Historic Load Data; Preliminary Load Forecasts; Preliminary Local RAR Filings; Year-Ahead System Resource Adequacy Compliance Filings; Year-Ahead Local Resource Adequacy Compliance Filings; and Month-Ahead System Resource Adequacy Compliance Filings.

2. Delegation of authority to Energy Division to issue citations and levy Scheduled Penalties for Specified Violations will allow prompt action by Staff.

3. Prompt action by Staff is necessary to protect consumers and fulfill the objectives of the Commission's resource adequacy program and Public Utilities Code section 380.

CONCLUSIONS OF LAW:

1. Public Utilities Code section 380 authorizes and directs the Commission: (1) to exercise its enforcement powers to ensure compliance with resource adequacy requirements; (2), to enforce resource adequacy requirements in a non-discriminatory manner; (3) to minimize enforcement requirements and costs; (4) to obtain sufficient information to enable the Commission to determine compliance with the resource adequacy requirements established by the Commission; and (5) to authorize the "most efficient and equitable means" to achieve the objectives of the statute.

2. The Commission has the power to act as an enforcement agency and to ensure that penalties are promptly prosecuted and collected pursuant to Public Utilities Code section 2101.

3. Public utilities are subject to Commission enforcement action and penalties pursuant to Public Utilities Code sections 2102-2105, 2107, 2108 and 2114.

4. Pursuant to Public Utilities Code section 394.24, electric service providers are subject to Commission enforcement action pursuant to Public Utilities Code sections 2102-2105, 2107, 2108 and 2114 as if they were public utilities.

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5. Community choice aggregators are subject to enforcement action pursuant to Public Utilities Code section 2111.

6. Under California law, including Public Utilities Code section 7, the Commission may delegate authority to its Staff to perform certain functions.

7. The Scheduled Penalties set forth in Appendix A are reasonable, will achieve the objectives of the Commission's resource adequacy program and Public Utilities Code section 380, and will effectively deter future violations.

8. D.06-06-064 determined the penalty for failure to file the Year-Ahead Local Resource Adequacy Compliance Filing is $40 kw-year times the LSE's Local RAR procurement obligation; this penalty is not the subject of this citation program, but will be enforced through formal Commission proceedings.

9. The proposed procedures for the citation program fulfill the objectives of Public Utilities Code section 380, and ensure due process, fairness and efficiency in the application of the citation program.

THEREFORE, IT IS ORDERED THAT:

1. The citation program described above and the Scheduled Penalties for the Specified Violations, Appendix A, are hereby adopted.

2. Authority is delegated to Energy Division to issue citations and levy Scheduled Penalties for the Specified Violations set forth in Appendix A to enforce compliance by LSEs within the service territories of California's three largest investor-owned electric utilities with resource adequacy requirements.

3. The issuance of a citation for a Specified Violation is not mandatory. In enforcing compliance with Resource Adequacy filing requirements or in response to any specified violation, the Commission may initiate any formal proceeding authorized by the California Constitution, the Public Utilities Code, other state and federal statutes, court decisions or decrees, the Commission's Rules of Practice and Procedure, or prior Commission orders, decisions, rules, directions, demands or requirements, and pursue any other remedy authorized by the California

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Constitution, the Public Utilities Code, other state or federal statutes, court decisions or decrees, or otherwise by law or in equity.

4. Nothing in this Resolution bars or affects the rights or remedies otherwise available to other persons or government agencies.

5. Resolution E-4017 is enacted.

6. This Resolution is effective today.

I hereby certify that this Resolution was adopted by the Public Utilities Commission at its regular meeting on October 5, 2006. The following Commissioners approved it:

STEPHEN LARSON
Executive Director

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

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APPENDIX A:
SPECIFIED VIOLATIONS AND SCHEDULED PENALTIES

Specified Violation	**Scheduled Penalty**
Failure to file Historic Load Data at the time or in the manner required.	$1,000 per incident *plus* $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.
Failure to file a Preliminary Load Forecast at the time or in the manner required.	$1,000 per incident *plus* $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.
Failure to file a Month-Ahead System Resource Adequacy Compliance Filing at the time or in the manner required.	$1,000 per incident *plus* $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.
Failure to file a Preliminary Local RAR Compliance Filing, or a Year-Ahead System Resource Adequacy Compliance Filing at the time or in the manner required.	$1,000 per incident *plus* $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.
Failure to comply with a request for information from Energy Division or the CEC that is reasonably related to implementation of the resource adequacy requirements in the time or in the manner required.	$1,000 per incident *plus* $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.

(END OF APPENDIX A)

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EXHIBIT 3

Resolution E-4907, Registration Process for Community Choice Aggregators

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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4907**
February 8, 2018

R E S O L U T I O N

Resolution E-4907. Registration Process for Community Choice Aggregators.

PROPOSED OUTCOME:

- This resolution would publish and implement a registration process for Community Choice Aggregators.

SAFETY CONSIDERATIONS:

- There is no impact on safety.

ESTIMATED COST:

- Potential unquantifiable bundled ratepayer savings due to elimination of cost shifting of resource adequacy costs.

By the Commission's own initiative.

SUMMARY

The Commission through this Resolution proposes an informal process of review of Community Choice Aggregation (CCA) Implementation Plans pursuant to the requirements and directives of Public Utilities Code Section 366.2[1] and Decision (D.) 05-12-041. This process of review will coordinate with the timeline of the mandatory forecast filings of the Commission's Resource Adequacy program to ensure that newly launched and expanding CCAs comply with Resource Adequacy requirements, as established by Section 380, before they serve customers.

This Resolution will require Community Choice Aggregators (CCAs) to submit to a process that includes a timeline for submission of Implementation Plans; a

[1] All further references are to the Public Utilities Code unless otherwise specified.

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requirement to "meet and confer" between the CCA and the incumbent utility that can be triggered by either the CCA or the utility; a registration packet including a CCA's service agreement and bond; and a Commission authorized date to begin service.

This resolution could delay the dates in which some CCAs serve customers but for a limited period of time in most circumstances no longer than one year and if a new or expanding CCA cannot comply with the new timelines the resolution creates a process where the CCA can still seek a waiver to serve customers within several months of approval of their implementation plans.

This Resolution, in part, is responsive to the directive of D.05-12-041 instructing the Executive Director to publish steps for the submission of Implementation Plans, and addresses the current rapid growth of CCA programs. The filing deadlines in this Resolution are intended to coordinate with the timeline for mandatory forecast filings in the Resource Adequacy program.

BACKGROUND

Overview of Community Choice Aggregation

In 2002 the State Legislature enacted Assembly Bill (AB) 117 (codified at Section 366.2), authorizing the creation of Community Choice Aggregators (CCAs). The Commission implemented the provisions of AB 117 in D.04-12-046, and D.05-12-041, among other Decisions.

D.05-12-041 directed the Executive Director to prepare and publish instructions for CCAs and utilities which would provide a forum for the CCA and the utility to understand the CCA's implementation plans and to assure that the CCA is able to comply with utility tariffs. The instructions should include a timeline and descriptions of the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, and notice to CCAs of the appropriate Cost Responsibility Surcharge (CRS) and registration of CCAs.

After D.05-12-041, no CCA came into formation until 2010 with the launch of Marin Clean Energy. From 2010 to 2015, two CCAs launched serving approximately 135,000 customer accounts statewide. From 2016 to 2017,

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CCA formation accelerated and 12 more communities launched or submitted CCA Implementation Plans to the Commission. As a result of this rapid growth in CCAs, it is appropriate now to address the directives of D.05-12-041 to create and publish processes for CCA implementation and registration.

Overview of CCA Implementation Plan Requirements

Section 366.2 authorizes the aggregation of electric loads by CCAs and establishes the broad requirements for implementing a CCA program. Section 366.2 grants the Commission authority over CCA implementation, and includes directives on the policy requirements of CCA programs, necessary implementation documents, timing requirements and deadlines for CCA implementation.

Section 366.2(c)(8) establishes the authority of the Commission to designate a CCA's start date with consideration of the impact on the electrical corporation's annual procurement:

> No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers within its boundaries until the commission determines the cost recovery that must be paid by the customers of that proposed community choice aggregation program, and provided for in subdivisions (d), (e), and (f). The commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.[2]

Policy Requirements for CCAs

Any CCA program must provide for universal access, reliability, equitable

[2] Section 366.2(c)(8).

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treatment of all classes of customers, and fulfill requirements established by state law or by the commission concerning aggregated service.[3]

Section 366.2(c)(4) states:

> A community choice aggregator establishing electrical load aggregation shall prepare a statement of intent with the implementation plan. Any community choice load aggregation established pursuant to this section shall provide for the following:
> (A) Universal access.
> (B) Reliability.
> (C) Equitable treatment of all classes of customers.
> (D) Any requirements established by state law or by the commission concerning aggregated service, including those rules adopted by the commission pursuant to paragraph (3) of subdivision (b) of Section 8341 for the application of the greenhouse gases emission performance standard to community choice aggregators.

Additionally, the implementation of a CCA program "shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."[4]

Implementation Documents and Requirements

Section 366.2 requires that CCAs submit an Implementation Plan and a Statement of Intent to the Commission and sets forth seven elements that Implementation Plans, and any subsequent changes to implementation plans, must contain.[5] Section 394.25(e) also requires that "an electric

[3] Section 366.2(c)(4).

[4] Section 366.2(a)(4).

[5] Section 366.2(c)(3) requires that Implementation Plans and any subsequent changes to implementation plans must be considered and adopted at a duly noticed public hearing and must contain all the following: (A)An organizational structure of the program, its operations, and its funding.(B)Ratesetting and other costs to participants, (C)Provisions for disclosure and due process in setting rates and allocating costs among participants.

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service provider or community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees" in the event of an involuntary return of CCA customers back to bundled service.[6]

Timing and Deadlines

The Public Utilities Code establishes requirements that direct the Commission how and when to respond to Implementation Plan filings. Within 10 days of an Implementation Plan filing, the Commission must notify the respective electrical cooperation of the filing.[7] Additionally, within 90 days of the filing of an Implementation Plan, the commission must "certify that it has received the plan" as well as provide the CCA with its findings regarding cost recovery.[8]

(D)The methods for entering and terminating agreements with other entities. (E)The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures. (F)Termination of the program. (G)A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

[6] Regarding the bond requirement in Section 394.25(e), in 2007 the Commission established in Resolution E-4133 an interim bond amount of $100,000. Currently the Commission is examining the permanent CCA bond calculation methodology in R.03-10-003.

[7] Section 366.2(c)(7) states:

> Within 90 days after the community choice aggregator establishing load aggregation files its implementation plan, the commission shall certify that it has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism. After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs as provided for in subdivisions (d), (e), and (f).

[8] Section 366.2(c)(7).

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Finally, the CCA "shall register with the Commission, which may require additional information to ensure compliance with basic consumer protection rules and other procedural matters."[9]

Overview of CCA Resource Adequacy Requirements

As more CCAs launch, it is important to consider how a registration process interacts with a CCA's compliance with its Resource Adequacy requirements.

All Load-Serving Entities (LSEs) are subject to Resource Adequacy (RA) requirements pursuant to Section 380. Section 380(k) defines LSEs to include CCAs. Additionally, D.05-12-041 in Conclusion of Law 19 states that "The utilities will not procure power on behalf of CCA customers as part of their resource adequacy planning."

The Commission in D.04-10-035 adopted a protocol which required LSEs to submit load forecasts using their best estimates of future customers and their loads. The Commission established a preliminary load forecast submission timeline in D.05-10-042.[10]

There are two mandatory annual load forecast deadlines that an LSE must comply with in order to receive an annual RA obligation responsibility for the following year.[11] First, an LSE must file a preliminary load forecast by mid-April for the following calendar year. An LSE then must file a revised forecast in

[9] Section 366.2(c)(15).

[10] D.05-10-042, page 83.

[11] D.04-10-035 adopted a protocol whereby LSEs are required to submit load forecasts using their best estimates of future customers and their loads. D.05-10-042 at page 83 specified the preliminary load forecast submission timeline and set April 15 as the date for the submission of preliminary load forecasts. D.11-06-022 at page 38 modified the year-ahead forecast timeline to include optional revisions to be submitted by Aug. 19th of each year. D.17-06-027 ordered that the revised August forecast be mandatory.

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August.[12] The August forecast was intended to refine and improve the accuracy of April forecast.[13]

The timeline of RA load forecast submissions has practical implications for newly forming CCAs and expanding CCAs. If an existing or pre-operational CCA does not submit an annual load forecast, they are not allocated a year-ahead RA obligation for the following year. In this scenario, the incumbent utility remains responsible for that load and procures RA for those customers, even if those customers are about to be served by a CCA. This scenario is most likely to occur if a CCA launches or expands service to customers (or additional customers in the case of an existing, yet expanding CCA) after the RA annual load forecast deadlines without filing an annual load forecast.

As a result, the utilities incur short-term power purchase costs for the customers of CCAs in their launch or expansion year. Utilities procuring for CCAs in their first launch or expansion year creates a cost shifting challenge. D.11-12-018 excluded power purchase transactions less than a year in term from the total portfolio calculation of the Power Charge Indifference Adjustment (PCIA). Consequently, Resource Adequacy contracts of over one year are captured by the PCIA, but Resource Adequacy contracts of less than one year are not captured by the PCIA. Therefore, such costs are borne by bundled customers, potentially resulting in millions of dollars annually of stranded costs and potentially in contravention of the indifference requirement of Section 366.2

Energy Division issued data requests to PG&E confirming the existence of stranded costs. Responses to these data requests were confidential because of the market-sensitive information they contain. The Commission does not rely on those responses in making the determinations made herein.

[12] Although D.11-06-022 modified the year-ahead forecast timeline to include optional revisions to be submitted by Aug. 19th of each year, later D.17-06-027 (OP 7) ordered that the revised August forecast be mandatory. The exact date of the August deadline varies by year.

[13] D.17-06-027, Finding of Fact 11.

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Public information illustrates the scale of load migration happening in the year-ahead RA program. Existing and new CCAs that were not a part of the year ahead 2018 RA process but plan to serve load in 2018 would have been allocated a System Peak RA requirement of approximately 3,616 MW and a local RA requirement of approximately 1,793 MW. These year-ahead RA requirements were met by the utilities that currently serve these customers. Some of these costs are recovered by the PCIA, however, any contracts less than one year are not captured by the PCIA and are borne by remaining bundled customers. Due to the confidentiality of utility's market position, the proportion of those contracts that are less than one year cannot be disclosed publicly.

In addition, if the California Independent System Operator (CAISO) procures back-stop capacity through its capacity procurement mechanism (CPM), it appears based on the CAISO's tariff language these costs will be allocated only to those LSEs that exist at the time of the designation (annual designations would occur in December, before the compliance year). It is not yet clear if the PCIA addresses this potential cost-shifting issue.

DISCUSSION

D.05-12-041 ordered the Executive Director to develop and publish two distinct processes in Ordering Paragraphs (OP) 8 and 10 of that Decision.

D.05-12-041 Ordering Paragraph 8 Implementation

Ordering Paragraph 8 requires the Executive Director to develop and publish the steps of an informal process of review that provides a forum for the CCA and the utility to understand the CCA's Implementation Plans and assures that the CCA is able to comply with the utility's tariffs.

The goal of this "forum" is to "facilitate the smoother operation of the CCA where its policies, practices, and decisions may affect the utility and its customers."[14] The operation and launch of a CCA program inherently requires logistical coordination between the utility and the CCA, and many CCA-utility

[14] OP 8, D.05-12-041.

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partnerships must engage in these kinds of information-sharing discussions to facilitate smooth transitions to CCA service.

In order to comply with the directive of Ordering Paragraph 8, at the request of either the CCA or the utility, the parties must "meet and confer" as soon as reasonably practical. If the first attempts at resolution are not successful, the parties are required to meet in person. Should the parties be unable to reach consensus after the in-person meeting(s), either party may request that Energy Division assist by sponsoring a moderated in-person discussion between the parties. Such a request should come in the form of a request to the Director of Energy Division explaining the general nature of any unresolved issues regarding CCA compliance with utility tariffs. During the "meet and confer" parties shall discuss the contents of the CCA's Implementation Plan and any relevant issues with compliance with utility tariffs.

D.05-12-041 Ordering Paragraph 10 Implementation

Ordering Paragraph 10 of D.05-12-041 requires the Executive Director to prepare and publish instructions for CCAs and utilities that includes a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate Cost Responsibility Surcharges (CRS), and registration of CCAs.

Adopted Timeline for 2019 and Beyond

Appendices A and B of this Resolution include a timeline of the CCA registration process, including the timeline adopted by this Resolution.

The Prior Timeline in Appendix B reflects the current practice of CCA registration. The statutory deadlines in the Prior Timeline were established in Section 366.2. However, several milestones in the Registration process did not have deadlines defined by statute. These milestones are represented as "undefined" in the Prior Timeline. D.12-05.041 included an illustrative registration timeline based on statutory deadlines associated with CCA implementation.[15]

[15] D.05-12-041, Attachment D.

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The Adopted Timeline modifies the Prior Timeline and the Illustrative Timeline (proposed in D.05-12-041 Attachment D) in several respects. First, the Adopted Timeline includes a deadline by which Implementation Plans must be received in order for CCAs to serve new load beginning January 1 of the following year. The goal of this requirement is to assist the proposed CCA in securing the certification and registration within enough time to file its preliminary load forecast by mid-April in order to serve load the following calendar year.

Second, the Adopted Timeline includes the Meet-and-Confer option for the CCA and the utility to discuss how the CCA will conform its operations to the utility's tariff requirements. Third, the Adopted Timeline includes the deadlines for submission of CCA RA load forecasts in the year prior to a CCA beginning to serve load. Fourth, the Adopted Timeline includes a deadline by which the CCA must submit its Registration Packet and receive confirmation of registration.

In order to coordinate the launch of a new or expanding CCA with the RA requirements, the Implementation Plan and Statement of Intent must be submitted to the Commission on or before January 1 in order to serve load in the following year.[16]

These requirements are authorized by Section 366.2(c)(4), which requires a CCA to "provide for universal access, reliability, equitable treatment of all classes of customers, **and any requirements established by state law or by the commission concerning aggregated service**."[17] Additionally, Load-Serving Entities, including CCAs, must comply with RA requirements pursuant to Section 380(a). Current RA rules require all LSEs to file an annual load forecast if they plan to serve load in the following year. Additionally, Section 366.2(c)(8) also supports this action and compels the Commission to "designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission."

[16] For example, a new or expanding CCA intending to serve new load in 2020 must submit its Implementation Plan on or before January 1, 2019.

[17] Section 366.2(c)(4), emphasis added.

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Thus, in order to comply with the year-ahead RA process, Implementation Plans, including Implementation Plans of an existing CCA that expands its territory, must be received by January 1 in order to serve load in the following year

Adopted Timeline for Transition Year Only (2018)

a. CCAs that filed by December 8, 2017

Prior to the mailing of the draft of this Resolution on December 8, 2017, the following Implementation Plans were submitted to the Commission:

1. Los Angeles Community Choice Energy
2. East Bay Community Energy
3. Redwood Coast Energy Authority Expansion to the City of Ferndale
4. Monterey Bay Community Power
5. Pioneer Community Energy
6. City of Rancho Mirage
7. Valley Clean Energy Alliance
8. City of Solana Beach
9. City of San Jose
10. MCE's expansion to the unincorporated areas of Contra Costa County; the cities of Concord, Martinez, Oakley, Pinole, Pittsburg and San Ramon; and the towns of Danville and Moraga

Collectively these Implementation Plans represent approximately 3,600 MW of new CCA load for 2018. This resolution has no effect on these 10 Implementation Plans or expansions

b. CCAs that filed after December 8, 2017

Following the mailing date of this Resolution on December 8, 2017, the following Implementation Plans have been submitted to the Commission:

1. Desert Community Energy
2. King City
3. Riverside CCA
4. Silicon Valley Clean Energy's Expansion to Milpitas
5. Los Angeles Community Choice Energy's Expansion to serve an additional 21 cities

Collectively these additional Implementation Plans represent approximately 1700 MW of new CCA load that CCAs express a desire to serve in 2018. These five CCAs are impacted by the new timeline adopted in this resolution and may serve load no sooner than January 1, 2019, assuming all deadlines set forth below are met, unless these CCAs apply for a waiver from this resolution to serve customers in 2018 as set forth in section (c) below.

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Energy Division will complete an expedited review of the Implementation Plans submitted by the five CCAs above as well as any additional Implementation Plans and registration packages received on or before March 1, 2018. Energy Division will complete its review by April 13, 2018. CCAs certified by April 13, 2018 must submit their registration packets (including signed service agreements and bond) no later than April 20, 2018 so that those CCAs are certified and registered before the Resource Adequacy annual load forecast deadline in April 2018. This will allow these CCAs to serve load in 2019.

c. Waiver Process

Any new or expanding CCA may request a waiver from the timelines set forth in this resolution in order to begin service in that new or expanded territory prior to January 1, 2019. To request a waiver either:

A. The CCA and utility in whose service territory the CCA intends to begin service shall jointly submit a Tier 1 Advice Letter no later than 75 days prior to the RA compliance month in which the CCA wishes to begin service. This Advice Letter shall provide notification that the utility and CCA mutually agree (via payment, allocation of RA or a combination thereof) that they have addressed RA requirements and cost responsibility concerns raised by the intra-year load migration for 2018.[18] Notification of agreements must include what categories of RA for what periods are being satisfied; or,

B. If no agreement is reached, the CCA shall file a Tier 1 Advice Letter no later than 75 days prior to the RA compliance month in which the CCA wishes to begin service. This Advice Letter shall provide notification that the utility and the CCA are unable to reach agreement to address the RA requirements and cost responsibility concerns raised by the intra-year load migration for 2018, and shall state that the CCA agrees to be bound by a future Commission determination in the RA proceeding (R.17-09-020) regarding cost responsibility for intra-year load migration, subject to appellate rights under the Commission's Rules. The CCA then shall file a

[18] Any allocation of RA can be a portion of a contract, a group of contracts, a pro rata share of the portfolio, or a combination thereof in addition to other forms of payment not identified.

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motion in the RA proceeding seeking such a determination within 60 days of the submittal of the Advice Letter. Submittal of this Advice Letter allows the CCA to begin service in 75 days later and shifts RA responsibility from the utility to the CCA.

CCAs Forming in Small and Multi-Jurisdictional Utility Territories

Should a CCA form in a Small and Multi-Jurisdictional Utility (SMJU) territory, various procedural, cost-shifting, and other potential issues will be presented. Those issues are not being addressed in this Resolution, but the Commission expects to address these issues in an as yet determined forum.

Procedural Components for CCA Implementation Plans

Procedure for Submission and Certification of Receipt

This Resolution adopts a new deadline for submission of Implementation Plans. Implementation Plans will be submitted to the Director of the Energy Division both via email and a hard copy on or before January 1[19] in order to serve load in the following year.[20] Within 90 days of receiving an Implementation Plan, the Energy Division will certify that the plan assuming it meets all requirements.

Notice to Customers

This Resolution adopts no changes for Notice to Customers. Implementation Plans shall include the timing of notices sent to utility customers who will be transitioned to CCA service.

Notice to Customers of the Appropriate Cost Responsibility Surcharge (CRS)

This Resolution adopts no changes for Notice to Customers of the Appropriate CRS. The current Cost Responsibility Surcharge (CRS) has three major components: the Department of Water Resources (DWR) Bond Charge, the Competitive Transition Charge, and the Power Charge Indifference Adjustment (PCIA).

[19] Except for 2018, where plans may be submitted by March 1, 2018.

[20] For 2018, Energy Division will certify plans by 4/13 if received by 3/1/18 as long as plans are reasonably complete and meet all requirements.

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CCAs shall include in their Implementation Plans how they will notify customers of the applicable CRS. The PCIA methodology is currently under reconsideration in R.17-06-026.

Registration of CCAs

This Resolution adopts two new deadlines for CCA registration. First, this Resolution requires that a CCA submit its registration packet to the CPUC within 90 days of filing its Implementation Plan. Second, this Resolution requires that if the Registration Packet is complete, the CPUC will confirm the CCA's registration within 120 days of the CCA submittal of its Implementation Plan assuming it meets all requirements.

To register, a CCA must submit its registration packet including a signed service agreement with the utility and a bond pursuant to Section 394.25 (e). The interim bond amount was set to $100,000 in Resolution E-4133 (2007) and the amount of the bond is currently under consideration in R.03-10-003.

Once a bond has been submitted, Energy Division will issue a registration letter confirming completion of all registration requirements. After a potential or expanding CCA has fulfilled the above requirements, it may initiate service to its new customers no earlier than the service date authorized by this Resolution.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. The draft Resolution was mailed for Comments on December 8, 2017.

The deadline for comments was extended to January 11, 2018 and reply comments were allowed seven days later.

Over 60 comments and reply comments were received from the public, including numerous individual stakeholders as well as organizations. Of those comments, the majority opposed this resolution. The Joint Utilities (SDG&E, SCE and PG&E), TURN, ORA, and the Coalition of California Utility Employees generally

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supported Resolution E-4907, with some caveats. Comments primarily focused on the following topics: timing, policy effects, and due process.

Timing

Many comments expressed opposition to Draft Resolution E-4907 and urged the Commission to delay action on Resolution. Many comments stated that Commission consideration of the Resolution in January or February 2018 presented too short a time period for adequate review and analysis.

Resolution E-4907 was held from the January 11, 2018 Commission meeting and scheduled for the February 8, 2018 Commission meeting. The deadline for comments was extended from December 29, 2017 to January 11, 2018. Reply comments were accepted with a deadline of January 18, 2018. The Commission is satisfied that it has provided adequate time for comment and has the information that it needs to decide the issues presented by this resolution.

Policy Effects

Some opposing commenters cited the significant negative impact to nascent CCA programs and expanding CCAs for 2018 and for 2019. They asserted that Draft Resolution E-4907 places substantial and unnecessary burdens on newly forming CCAs. Numerous stakeholders stated that communities invested significant time and resources to launch CCA programs and that these communities would be unfairly harmed in delaying a CCA's service date. Delay of service to new load represents a delay in associated revenues and program benefits according to some commenters. Many asserted that the proposed timeline was arbitrary.

Although Resolution E-4907 may delay some CCAs' desired date to begin service, any such delay would be for a finite period and for the purpose of avoiding unlawful cost shifting. Section 366.2 (c) (8) requires:

> No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers within its boundaries until the commission determines the cost recovery that must be paid by the customers of that proposed community choice aggregation program, as provided for in subdivisions (d), (e), and (f). The commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, **taking into consideration the**

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> **impact on any annual procurement plan of the electrical corporation that has been approved by the commission**. [emphasis added.]

Here, Resolution E-4907 designates the earliest possible effective date, taking into account the year-ahead requirements of the Resource Adequacy program in conjunction with our responsibility to avoid shifting costs onto bundled customers. Resource Adequacy is a key component of annual procurement planning and a responsibility of all Load-Serving Entities. The timeline requirements adopted by Resolution E-4907 are allowed by Section 366.2 (c) (8). Revisions to the resolution adjust compliance dates to ensure that the new provisions are consistent with the requirements of Section 366.2(c)(8) that the commission designate the earliest possible effective date for implementation of a community choice aggregation program.

Due Process

Numerous commenters assert that the resolution violates their due process rights. We disagree. The changes in the CCA timeline made by this resolution are an exercise of authority the Commission has had since 2002. Section 366.2(c)(8) establishes the authority of the Commission to designate a CCA's start date with consideration of the impact on the electrical corporation's annual procurement. The Commission could have set a start date/timeline for a CCA in a letter certifying its Implementation Plan. There is no substantive difference here, where the Commission is simply setting that start date/timeline for all CCAs.

Ordering Paragraph 10 of D.05-12-041, moreover, requires the Executive Director to "prepare and publish instructions for CCAs and utilities that includes a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate CRS, and registration of CCAs." This resolution effectuates that order.

Commenters assert that there was no opportunity to be heard. We disagree. Comments on draft resolutions are normally afforded about 20 days to comment.[21] Here, in response to requests from commenters, additional time was

[21] Compare section 311(g)(1) with California Public Utilities Commission, Rules of Practice and Procedure (Rules), Rule 14.5.

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afforded for comments. In addition, reply comments, while not normally allowed, were allowed.
Finally, two additional changes were made in response to comments. First, the deadline to submit Implementation Plans in 2018 has been moved forward to March 1, 2018, allowing several additional CCAs to begin service in 2019. Second, CCAs that desire to serve in may request a waiver if they reach an agreement with the incumbent utility to resolve RA cost-shifting concerns. These changes provide greater flexibility to CCAs on the date they can begin service.

FINDINGS AND CONCLUSIONS

1. Ordering Paragraph 8 of D.05-12-041 requires that the Executive Director develop and publish the steps of an informal process of review that provides a forum for the CCA and the utility to understand the CCA's implementation plans and assures the CCA is able to comply with utility tariffs.

2. Ordering Paragraph 8 of D.05-12-041 requires that the forum be mandatory at the request of either the utility or the CCA and where the request is presented in writing with a recitation of disputed items or areas of concern. The process shall implicate no approvals, either formal or informal, from the Commission. Utility tariffs shall describe the meet and confer process for resolving disputes over operational issues prior to initiation of services.

3. The Commission should develop and publish the steps of an informal process of review that provides a forum for CCAs and utilities as directed in Ordering Paragraph 8 of D.05-12-041.

4. Ordering Paragraph 10 of D.05-12-041 requires the Executive Director to prepare and publish instructions for CCAs and utilities that includes a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate

5. The Commission should prepare and publish instructions for CCAs and utilities that includes a timeline and describes the procedures for submitting and certifying receipt of the Implementation Plan, notice to customers, notice to CCAs of the appropriate Cost Responsibility Surcharge (CRS), and

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registration of CCAs. Cost Responsibility Surcharge (CRS), and registration of CCAs.

6. CCAs must comply with the Resource Adequacy requirements as set forth in Public Utilities Code Section 380 before beginning service.

THEREFORE IT IS ORDERED THAT:

1. Within 14 days of the effective date of this Resolution, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E), shall update their tariffs and submit Tier 2 Advice Letters with the adopted timeline and procedures listed in Appendix A.

2. Prospective or expanding Community Choice Aggregators who have not yet submitted an Implementation Plan as of December 8, 2017 shall file their Implementation Plans pursuant to the adopted timeline and procedures listed in Appendices A and B and fulfill the Resource Adequacy portion of Appendices A and B prior to initiating service to customers unless they receive a waiver from the Commission as described in Paragraph 3 below. This Resolution is not retroactive.

3. Any new or expanding CCA may request a waiver from the timelines set forth in this resolution in order to begin service prior to the deadlines in Appendices A and B. To request a waiver either:

   A. The CCA and utility in whose service territory the CCA intends to begin service shall jointly submit a Tier 1 Advice Letter no later than 75 days prior to the RA compliance month in which the CCA wishes to begin service. This Advice Letter shall provide notification that the utility and CCA mutually agree (via payment, allocation of RA or a combination thereof) that they have addressed RA requirements and cost responsibility concerns raised by the intra-year load migration for 2018. Notification of agreements must include what categories of RA for what periods are being satisfied; or,

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B. If no agreement is reached, the CCA shall file a Tier 1 Advice Letter no later than 75 days prior to the RA compliance month in which the CCA wishes to begin service. This Advice Letter shall provide notification that the utility and the CCA are unable to reach agreement to address the RA requirements and cost responsibility concerns raised by the intra-year load migration for 2018, and shall state that the CCA agrees to be bound by a future Commission determination in the RA proceeding (R.17-09-020) regarding cost responsibility for intra-year load migration, subject to appellate rights under the Commission's Rules. The CCA then shall file a motion in the RA proceeding seeking such a determination within 60 days of the submittal of the Advice Letter. Submittal of this Advice Letter allows the CCA to begin service in 75 days later and shifts RA responsibility from the utility to the CCA.

4. Commission staff will process Implementation Plans pursuant to the adopted timeline and procedures listed in Appendices A and B.

5. The Commission will revisit this process, if necessary, depending on the outcome of R.03-10-003 or successor proceedings.

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This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on February 8, 2018; the following Commissioners voting favorably thereon:

/s/*TIMOTHY J. SULLIVAN*
TIMOTHY J. SULLIVAN
Executive Director

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

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Appendix A: Adopted CCA Registration Timeline and Procedures

Date	Action
Day 1, Year 1 (On or before January 1 Year 1)[22]	(1) The prospective or expanding CCA submits its Implementation Plan to Energy Division and serves it on the R.03-10-003 Service List, on the R.16-02-007 Service List, and on the R.17-09-020 Service List, or successor proceedings.
Day 1 – 10, Year 1	(1) The CPUC notifies the Utility servicing the customers that are proposed for aggregation that an implementation plan initiating their CCA program has been filed.
Day 1 – 60, Year 1	(1) The CCA provides a draft customer notice to CPUC's Public advisor. (2) Within 15 days of receipt of the draft notice, the Public Advisor shall finalize that notice and send it to the CCA.
DAY 1 – 90, Year 1[23]	(1) The CPUC sends a letter confirming that it has received the Implementation Plan and certifying that the CCA has satisfied the requirements of an Implementation Plan pursuant to Section 366.2(c) (3). This letter informs the CCA about the cost recovery mechanism as required by P.U. Code Section 366.2(c)(7). If and when the CPUC requests additional information from a CCA, the CCA shall respond to CPUC staff within 10 days, or notify the staff of a date when the information will be available. (2) The CPUC provides the CCA with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (P.U. Code Section 366.2 (c) (7).)

[22] For Plans to be submitted in 2018 to serve load in 2019, this deadline is extended to March 1, 2018.

[23] For Plans submitted by March 1, 2018, CPUC will complete review by April 13, 2018.

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	(3) The CCA and the Utility should Meet-and-Confer regarding the CCA's ability to conform its operations to the Utility's tariff requirements.
DAY 1 – 90, Year 1[24]	(1) The CCA submits its registration packet to the CPUC, including: a. Signed service agreement with the utility, and b. CCA interim bond of $100,000 or as determined in R.03-10-003
Day 90 – 120, Year 1[25]	(1) If the registration packet is complete, the CPUC confirms Registration as a CCA.
April, Year 1	(1) The CCA submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)
August, Year 1	(1) The CCA submits its updated year-ahead RA forecast
October Year 1 (75 days before service commences)	(1) CCAs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.
Within 60 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send its first notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A))
Within 30 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send a second notice to the prospective customers describing the terms and conditions of the services being offered and the customer's opt-out opportunity prior to commencing its automatic enrollment. (P.U. Code Section 366.2 (c) (13) (A)) (2) Once notified of a CCA program, the Utility shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process. (P.U. Code Section 366.2 (c) (16))
January 1, Year 2	(1) CCA begins service.
Following the CCA's Automatic Customer Enrollment	(1) The CCA shall inform participating customers for no less than two consecutive billing cycles that: a. They have been automatically enrolled into the CCA program and that each customer has the right to opt out of the CCA program without penalty. (P.U. Code Section 366.2 (c) (13)(A)(i).)

[24] For 2018, the bond and signed service agreement must be submitted by April 20, 2018.

[25] For 2018, the CPUC will confirm registration by April 27, 2018.

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	b. Terms and conditions of the services being offered. (P.U. Code Section 366.2 (c) (13)(A)(ii).)

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Appendix B: Schematic Comparison of Prior and Adopted Timelines for CCA Registration Process

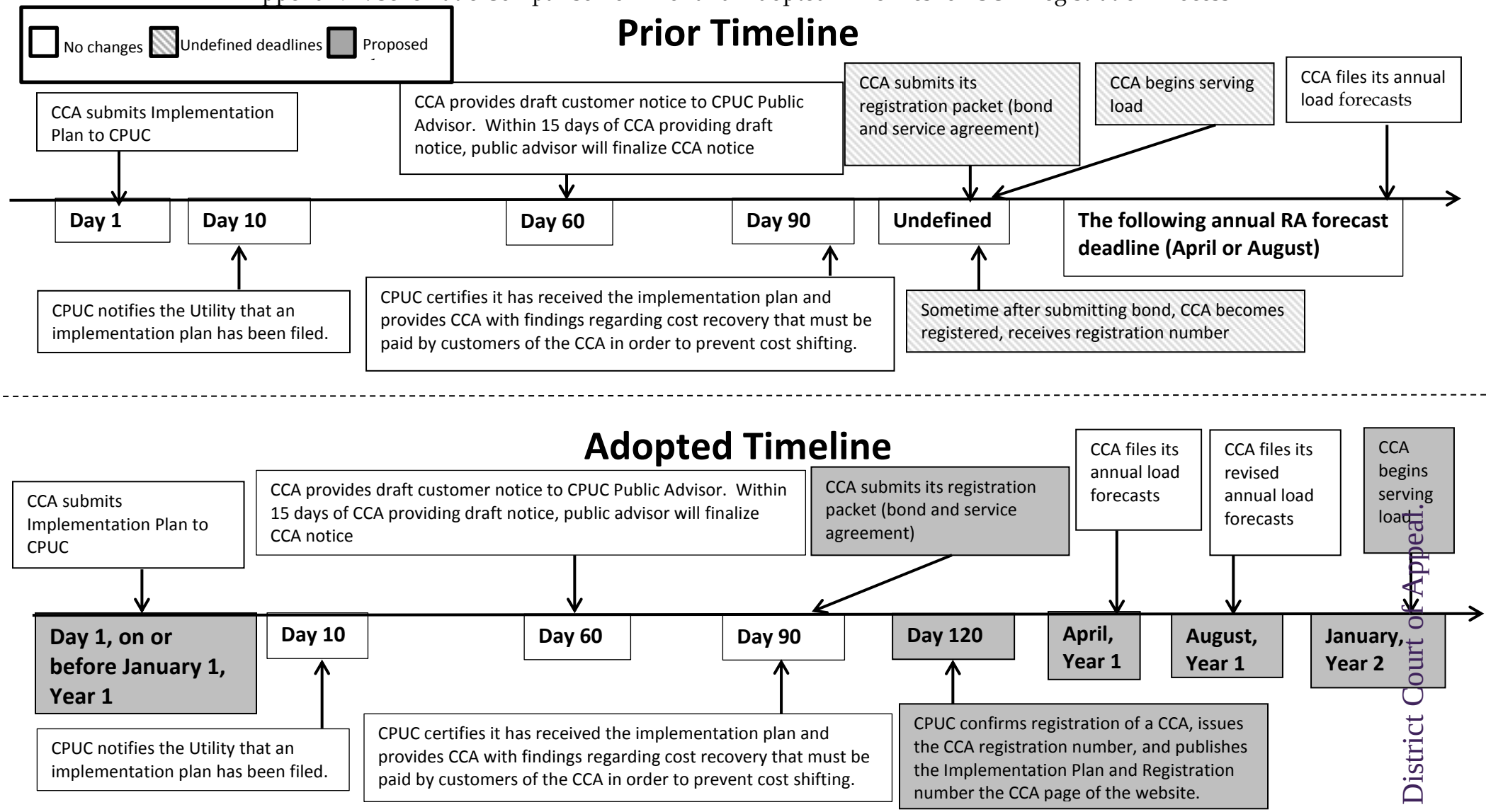

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EXHIBIT 4

D.23-06-029: Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements

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Decision 23-06-029 June 29, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2024 - 2026, FLEXIBLE CAPACITY OBLIGATIONS FOR 2024, AND PROGRAM REFINEMENTS

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2024 - 2026, FLEXIBLE CAPACITY OBLIGATIONS FOR 2024, AND PROGRAM REFINEMENTS

Summary

This decision adopts Local Capacity Requirements for 2024 - 2026, Flexible Capacity Requirements for 2024, and refinements to the Resource Adequacy program scoped as Phase 3 of the Implementation Track, including modifying the planning reserve margin for 2024 and 2025 and modifying the demand response counting requirements.

This proceeding is closed.

1. Background

On October 7, 2021, the California Public Utilities Commission (Commission or CPUC) issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider program reforms and refinements, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs). Additional information on the procedural history of this proceeding is provided in the OIR.

A Scoping Memo and Ruling for this proceeding was issued on December 2, 2021. The Scoping Memo identified the issues to be addressed in this proceeding, set forth a schedule and process for addressing those issues, and established two tracks for this proceeding (the Implementation Track and the Reform Track). Under the Implementation Track, the Scoping Memo divided the track into Phases 1, 2, and 3. Issues scoped as Phase 1 of the Implementation Track were addressed in Decision (D.) 22-03-034. Issues scoped as Phase 2 of the Implementation Track and issues scoped as the Reform Track were addressed in D.22-06-050.

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On September 2, 2022, an Amended Scoping Memo and Ruling was issued that designated issues for Phase 3 of the Implementation Track and Phase 2 of the Reform Track. Issues scoped as Phase 2 of the Reform Track were addressed in D.23-04-010. This decision resolves issues scoped as Phase 3 of the Implementation Track.

Proposals on Phase 3 of the Implementation Track were filed on January 20, 2023 by: Alliance for Retail Energy Markets (AReM), California Community Choice Association (CalCCA), Central Coast Community Energy (CCCE), Middle River Power LLP (MRP), Pacific Gas and Electric Company (PG&E), Vistra Corp. (Vistra), and Western Power Trading Forum (WPTF). The Commission's Energy Division's Phase 3 proposals were filed by an Administrative Law Judge's (ALJ) ruling on January 20, 2023. A workshop on Phase 3 proposals was held on February 8, 2023.

On February 2, 2023, the California Energy Commission's (CEC) Qualifying Capacity of Supply-Side Demand Response (DR) Working Group Report (CEC Report) was issued via an ALJ ruling. On February 15, 2023, an ALJ ruling was issued that set forth questions regarding the CEC Report to address in comments and a schedule for comments. On February 24, 2023, an ALJ ruling notified that the CEC had provided the incorrect, draft version of the CEC Report and attached the corrected, final version of the CEC Report.

Opening comments on Phase 3 proposals were submitted on February 24, 2023 by: AReM; Bonneville Power Administration (BPA); CalCCA; California Efficiency + Demand Management Council, CPower, and OhmConnect, Inc. (collectively, Joint Demand Response (DR) Parties); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); CAISO's Department of Market Monitoring (DMM); California Large

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Energy Consumers Association (CLECA); Calpine Corporation (Calpine); CCCE; GenOn Holdings, Inc. (GenOn); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Marin Clean Energy (MCE); Microsoft Corporation (Microsoft); MRP; PG&E; Public Advocates' Office (Cal Advocates); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US). L.P. (Shell Energy); Silicon Valley Clean Energy Authority (SVCE); Southern California Edison (SCE); Union of Concerned Scientists, California Environmental Justice Alliance, and National Resources Defense Council (collectively, Joint Environmental Parties); Vistra; and WPTF.

Reply comments on Phase 3 proposals were filed on March 3, 2023 by: American Clean Power – California (ACP-CA), AReM, CAISO, California Wind Energy Association (CalWEA), Cal Advocates, CalCCA, CESA, CLECA, DMM, Enchanted Rock, LLC (Enchanted Rock), GenOn, GPI, IEP, Mainspring Energy, Inc. (Mainspring), Microsoft, MRP, OhmConnect, Inc. (OhmConnect), PG&E, SCE, SDG&E, and Shell Energy.

On March 1, 2023, opening comments on the CEC Report were filed by: CAISO; Cal Advocates; California Efficiency + Demand Management Council and CPower (jointly, CEDMC/CPower); CLECA; Demand Side Analytics (DSA); OhmConnect; PG&E; SDG&E; SCE; and WPTF. Reply Comments on the CEC Report were filed on March 8, 2023 by: CEDMC/CPower, CLECA, OhmConnect, PG&E, and SCE.

2. Submission Date

The matter for this decision was submitted on March 8, 2023.

3. Issues Before the Commission

The scope of Phase 3 of the Implementation Track, as adopted in the September 2, 2022 Amended Scoping Memo, are summarized below:

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1. Consider 2024-2026 Local Capacity Requirements (LCR).
    a. CAISO performs an annual LCR study, which is submitted into the RA proceeding and used to adopt local RA procurement requirements for the next three compliance years. For Phase 3, this will be for the 2024-2026 RA compliance years. The draft CAISO LCR study will be submitted to the Commission in April 2023 and the final LCR study will be submitted in May 2023. The Commission intends to issue a decision by the end of June 2023 so that jurisdictional LSEs and the central procurement entities have sufficient time to obtain the resources to meet local RA procurement requirements.
2. Consider 2024 Flexible Capacity Requirements (FCR).
    a. Similar to the LCR process, CAISO performs an annual FCR study, which is used to adopt flexible RA requirements for the following compliance year. The final FCR study will be submitted in May 2023. The Commission intends to issue a decision by the end of June 2023 so that jurisdictional LSEs have sufficient time to obtain the resources to meet their flexible RA procurement requirements for 2024.
3. Consider modifications to the Planning Reserve Margin (PRM) for the 2024 RA year and beyond, including Energy Division's recent loss of load expectation (LOLE) study in the Integrated Resource Planning (IRP) proceeding, or a future LOLE study for RA to be submitted into this proceeding no later than January 2023.
4. Consider modifications to the qualifying capacity (QC) methodology for demand response for the 2025 RA year, including the CEC Working Group report to be submitted into this proceeding by February 1, 2023.
5. Other time-sensitive issues identified by Energy Division or by parties.

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4. Discussion

4.1. 2024 – 2026 Local Capacity Requirements

In D.06-06-064, the Commission established the local RA framework and adopted local procurement obligations for 2007. The Commission determined that a study of the LCR, performed by CAISO, would form the basis for the local RA program and that the local requirements should be based on a level of reliability described as "Option 2" in CAISO's LCR study report.[1] CAISO conducts an annual LCR study and the Commission resets local procurement obligations each year after review and approval of CAISO's recommendations. A series of subsequent decisions (most recently in D.22-06-050) established local procurement obligations for 2008 through 2025. In D.19-02-022, multi-year local RA requirements were adopted for a three-year duration beginning with the 2020 compliance year.

In PG&E's and SCE's service territories, beginning for the 2023 RA compliance year, a central procurement entity (CPE) framework was adopted and local requirements are no longer allocated to LSEs in PG&E's and SCE's distribution service areas. In SDG&E's service area, local RA requirements are still allocated to Commission-jurisdictional LSEs and each LSE must procure sufficient RA capacity resources in each local area to meet its obligations.

Each year from 2007 to 2019, CAISO used the Option 2 reliability criteria as the basis for the annual LCR study. In 2020, CAISO changed its LCR study methodology by updating the LCR criteria to align with current mandatory reliability standards developed by the North American Electric Reliability

[1] D.06-06-064 at 17.

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Corporation (NERC), the Western Electricity Coordinating Council (WECC), and CAISO.

CAISO's Draft 2024 Local Capacity Technical Report (Draft LCR Report) was submitted on April 6, 2023. Comments on the Draft LCR Report were filed on April 19, 2023 by: CalCCA and GPI. On April 20, 2023, Vistra served comments on the Draft LCR Report, with a motion to late-file its comments. Vistra's motion to late-file comments was granted on May 22, 2023.

CAISO's 2024 Final Local Capacity Technical Report (Final LCR Report) was submitted on May 1, 2023. Comments on the Final LCR Report were filed on May 8, 2023 by GPI. Reply comments on the Final LCR Report were filed on May 12, 2023 by CAISO.

CAISO's recommended 2024-2026 LCR values are summarized in the following table, with the recommended 2023-2025 LCR values provided for comparison.

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2024 - 2026 Local Capacity Requirements			
Local Area Name	**2024**	**2025**	**2026**
Humboldt	133	137	141
North Coast/North Bay	983	989*	853
Sierra	1212*	1263*	1314*
Stockton	750*	750*	750*
Greater Bay	7329*	7498*	7667*
Greater Fresno	2028*	2203*	2378*
Kern	427*	427*	427*
Big Creek/Ventura	1971	1110	1146
LA Basin	4413	4795	5177
San Diego/Imperial Valley	2834	3019	3205
Total	22080	22191	23058
* CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			

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2023 - 2025 Local Capacity Requirements			
Local Area Name	**2023**	**2024**	**2025**
Humboldt	141	143	144
North Coast/North Bay	857	899*	911*
Sierra	1150*	1199*	1248*
Stockton	579*	579*	579*
Greater Bay	7312*	7369*	7426*
Greater Fresno	1870*	1947*	2025*
Kern	439*	316*	318*
Big Creek/Ventura	2240	2258	2275
LA Basin	7529	5851	5944
San Diego/Imperial Valley	3332	3341	3351
Total	25449	23902	24221
* CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			

The Commission finds the recommended LCR values for 2024–2026 to be reasonable. Accordingly, CAISO's recommended 2024–2026 LCR values set forth in the table above are adopted.

4.2. 2024 Flexible Capacity Requirements

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined implementation guidelines. D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need:

> "Flexible capacity need" is defined as the quantity of resources needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Resources will be considered as "flexible capacity" if

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they can sustain or increase output, or reduce ramping needs, during the hours of "flexible need."[2]

This year, CAISO notified the Commission that the final Flexible Capacity Needs Assessment for 2024 (Final FCR Report) would not be filed by May 12, 2023 due to delays outside of CAISO's control. On May 4, 2023, an ALJ's ruling was issued that shortened the time for comments on the Final FCR Report. The ruling stated that once CAISO filed the Final FCR Report into the proceeding, parties would have until the end of the second business day to file responsive comments.

The Final FCR Report was filed on May 17, 2023. Comments on the Final FCR Report were filed by MRP on May 19, 2023. MRP expresses concern regarding CAISO's scaling of the Integrated Energy Policy Report (IEPR) load forecast.

The Final FCR Report contains the following figures for 2024, with the 2023 FCR figures provided for comparison.

[2] D.13-06-024 at 2.

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2024 Flexible Capacity Requirements					
NOTE: All numbers are in Megawatts	**CAISO System Flexible Requirement**	**CPUC Flexible Requirement**	**CPUC**		
			Category 1 (minimum)	**Category 2 (100% less Cat. 1 & 3)**	**Category 3 (maximum)**
January	23583	22554	6065	15361	1128
February	23925	22909	6160	15604	1145
March	24446	23246	6251	15833	1162
April	23817	22643	6089	15422	1132
May	23485	22293	8303	12875	1115
June	23897	22776	8483	13154	1139
July	20651	19836	7388	11456	992
August	22018	21087	7854	12179	1054
September	23135	22226	8278	12837	1111
October	22655	21745	5847	14811	1087
November	23081	22145	5955	15083	1107
December	20900	20093	5403	13685	1005
2023 Flexible Capacity Requirements					
NOTE: All numbers are in Megawatts	**CAISO System Flexible Requirement**	**CPUC Flexible Requirement**	**CPUC**		
			Category 1 (minimum)	**Category 2 (100% less Cat. 1 & 3)**	**Category 3 (maximum)**
January	21507	20487	6609	12854	1024
February	23815	22696	7321	14240	1135
March	24625	23313	7520	14627	1166
April	24250	22879	7380	14355	1144
May	22757	21433	9800	10561	1072
June	21403	20177	9226	9942	1009
July	19034	17971	8217	8855	899
August	20451	19318	8833	9519	966
September	22437	21345	9760	10518	1067
October	24443	23238	7496	14580	1162

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November	24732	23448	7564	14712	1172
December	22321	21167	6828	13281	1058

CAISO maintains a must-offer obligation under which an RA resource must be available for dispatch during standard hours under CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM). CAISO is required to annually determine the daily five-hour range for the standard hours, known as "availability assessment hours" (AAHs). AAHs are intended to correspond with the hours in which high demand conditions typically occur and thus, when RA resources are most critical to maintaining system reliability.

Likewise, the Commission identifies RA "measurement hours" to establish QC values for select resources, particularly non-dispatchable and demand response resources. The current RA measurement hours were adopted in D.10-06-036 and revised in D.18-06-030 and D.22-06-050. Currently, the CAISO AAHs and RA measurement hours are 5:00-10:00 p.m. for March and April, and 4:00–9:00 p.m. for all other months. These hours have also been used to determine when use-limited resources are required to be available under the maximum cumulative capacity (MCC) bucket structure.

In CAISO's 2023 Final FCR Report, CAISO states that based on its analysis of the distribution of the top five percent of load hours within each month from 2024 to 2026, it is necessary to add May to the spring season adopted in D.22-06-050 for the months of March and April and that the spring AAH should remain 5:00–10:00 p.m.[3] CAISO recommends that the AAH for winter and summer months (January to February and June to December) should remain 4:00-9:00 p.m. for 2024.

[3] CAISO Final Flexible Capacity Needs Assessment for 2024, May 16, 2023, at 32-36.

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Despite the brief review period available for the Final FCR Report, the Commission reviewed the FCR figures and finds that the figures appear reasonable. Accordingly, CAISO's recommended values set forth in the table above are adopted.

In addition, the Commission finds CAISO's revised AAHs for May to be reasonable and adopts the same revised hours for the RA measurement hours. This modification ensures that the Commission's measurement hours remain aligned with the CAISO's AAH window. Accordingly, the RA measurement hours shall be 5:00-10:00 p.m. for March, April, and May, and 4:00–9:00 p.m. for all other months beginning in the 2024 RA compliance year.

The DR MCC bucket and MCC bucket categories 1, 2, and 3 are based on the existing measurement hours. As such, it is also necessary to adjust the hours for the DR MCC bucket and MCC buckets 1, 2, and 3 to reflect the new revised measurement hours. Accordingly, the DR MCC bucket and MCC buckets 1, 2, and 3 are modified to reflect the newly adopted measurement hours, as follows:

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Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available at least 24 hours per month from May-September. For May, must be available Monday-Saturday for 4 consecutive hours between 5 PM-10 PM. For June-September, must be available Monday-Saturday for 4 consecutive hours between 4 PM-9 PM.	8.3%
1	Monday–Saturday, at least 100 hours per month. For February, total availability is at least 96 hours. January - February, June-December, 4 consecutive hours between 4 PM - 9 PM. March-May, 4 consecutive hours between 5 PM – 10 PM.	17.0%
2	Every Monday–Saturday. January-February, June-December, 8 consecutive hours that include 4 PM–9 PM. March-May, 8 consecutive hours that include 5 PM–10 PM.	24.9%
3	Every Monday–Saturday. January-February, June - December, 16 consecutive hours that include 4 PM – 9 PM. March-May, 16 consecutive hours that include 5 PM–10 PM.	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

4.3. Planning Reserve Margin

In D.22-06-050, the Commission stated that:[4]

> To balance the recognized and urgent need to increase the PRM for 2023 with the acknowledgement that additional LOLE modeling must be undertaken, the Commission finds it prudent to adopt a marginally increased PRM for 2023 and 2024 that falls within the 15 to 17 percent PRM range initially adopted in D.04-01-050. The Commission finds it appropriate to adopt a PRM of 16 percent for the 2023 RA year and a minimum 17 percent PRM for the 2024 RA year; accordingly, we adopt these requirements here.

[4] D.22-06-050 at 22.

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The Commission noted, however, that "the PRM for the 2024 RA year may be further revised in a June 2023 decision, after a review of Energy Division's updates to the LOLE modeling by stakeholders and the Commission."[5]

4.3.1. Summary of Proposals

Energy Division performed an LOLE study for 2024 that modeled the existing fleet of resources with updates for recent development and IRP filings, and made revisions to methodologies based on comments in 2022 on prior LOLE studies.[6] Energy Division performed LOLE studies using the current Strategic Energy & Risk Valuation Model (SERVM) dataset, which includes the 2021 IEPR demand forecast and the new 2022 baseline resource file as inputs. Energy Division no longer included any RESOLVE build out in the study and calibrated the model to identify LOLE events using the import constraint as the tuning variable instead of retiring thermal generation.

For the 2024 RA compliance year, Energy Division's LOLE study proposes a PRM of 18-20 percent for all months of the year, based on the modeled generation fleet and CEC load profiles.[7] In a separate Energy Division Staff proposal, Energy Division identifies four options for the 2024 PRM:[8]

(1) Maintain the status quo of 17 percent;
(2) Reduce the PRM to 16 percent (the 2023 PRM level);
(3) Increase the PRM to the PRM proposed in the LOLE study of 18-20 percent;
(4) Select a PRM between 16–20 percent.

[5] *Id*. at 23.

[6] *See generally* Energy Division's Loss of Load Expectation and Slice of Day Tool Analysis for 2024 (Energy Division LOLE Study).

[7] Energy Division LOLE Study at 27.

[8] Energy Division Phase 3 Proposals at 7.

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Energy Division estimates that based on an estimated September 2024 peak load forecast of 42,700 MW, the associated RA requirements would be as follows:[9]

PRM (%)	RA Requirement in MW
16	49,534
17	49,960
18	50,387
19	50,814
20	51,241

This equates to about a 430 MW increase in RA requirement for each percentage increase in PRM.

Energy Division states that any of the four options could be considered with an extension of the "effective PRM," which was first adopted in D.21-03-056 of Rulemaking (R.) 20-11-003, the OIR to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. Energy Division states that the effective PRM allows for the investor-owned utilities (IOU) to buy additional megawatts (MW) beyond their RA obligations and charge the costs to all customers as contingency resources.

In addition, Energy Division's LOLE study outlined steps that would be undertaken to calibrate the results of the LOLE study to calculate the PRM for the 24-hour slice-of day (SOD) framework.[10] Energy Division outlines the following steps:

[9] Energy Division Phase 3 Proposals at 6.

[10] Energy Division LOLE Study at 27.

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(1) Enter baseline portfolio from SERVM and calibrate to 0.1 via LOLE analysis, then the SERVM portfolio should inform the PRM used in the RA program;

(2) Calibrate portfolio to PRM requirements using SOD resource counting;

(3) Apply PRM to compliance requirement.

In its Phase 3 proposal, Energy Division highlights that when the PRM was being considered in 2021 and 2022, the CEC load forecast increased substantially, and that with the increased PRM, RA requirements for 2023 were 4-5 percent higher than in 2021.[11] In addition, Energy Division states that the modeled resource fleet for 2024 assumes 5,823 MW of nameplate capacity of resources that were in development as of November 2022. Given the large number of resources currently under development that were included in the 2024 LOLE modeling, as well as the significant delays developers have experienced in recent years, Energy Division is concerned that the study assumptions will not materialize, and resources will not be available to meet the estimated RA requirements.

For these reasons, Energy Division recommends maintaining the status quo at 17 percent PRM for 2024 and extending the effective PRM through 2025.[12] Energy Division states that the effective PRM could be set at a level equal to the difference between the modeled and adopted PRMs. For example, if the PRM is 17 percent and the modeled PRM is 20 percent, the effective PRM would be a range of MWs roughly equivalent to 3 percent of the Commission share of September load. Energy Division recommends that the effective PRM continue to apply to peak summer months of June - October, with IOUs able to use excess

[11] Energy Division Phase 3 Proposals at 5.

[12] *Id*. at 7.

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resources from existing portfolios to meet minimum target levels in June and October.

Energy Division further proposes that if the effective PRM is extended through 2025, all resources now eligible to be in the contingency resource bucket can remain contingency resources. Resources eligible to count towards the effective PRM would remain unchanged from D.21-12-015. Procurement targets should be divided between the three IOUs similar to the targets adopted in D.21-12-015 (900-1350 MW for SCE and PG&E; 200-300 MW for SDG&E). Energy Division seeks comments on whether deficient LSEs should be assigned costs first before allocating costs to all customers through the Cost Allocation Mechanism (CAM), as it is possible that the effective PRM will first cover any LSE RA deficiencies before adding to above-PRM procurement.

4.3.2. Comments on Proposals

Cal Advocates, CalWEA, GPI, and SCE support Energy Division's proposed PRM framework.[13] The parties generally state that this approach reasonably balances the LOLE results with the reality of available RA supply while ensuring reliability in 2024. SCE states that a tight RA market is precisely why it is reasonable to retain the current PRM framework and that increasing the PRM may create shortages, which will lead to excessive prices and excessive costs to customers.[14] SCE argues that retaining the effective PRM will keep costs down and provide reliability benefits because there are less stringent counting rules and fewer entities competing for the same resources. Cal Advocates

[13] Cal Advocates Opening Comments at 9, SCE Opening Comments at 2, CalWEA Reply Comments at 2, GPI Opening Comments at 1.

[14] SCE Reply Comments at 3.

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recommends that Energy Division quantify procurement delays, if possible, to provide a clearer picture of RA supply in 2024.

Cal Advocates, CalWEA, CESA, GPI, IEP, SCE, and CalCCA (with modifications) support extending the effective PRM.[15] CESA states that it would allow Emergency Load Reduction Program (ELRP) resources to continue counting towards reliability through 2025 and the program has been authorized through 2025. CalCCA supports the effective PRM only if resources that count towards the effective PRM are incremental to the RA stack because allowing RA-eligible resources to count towards the effective PRM adds competing demand for RA supply. AReM states that if the effective PRM is adopted, IOUs should be required to demonstrate that the effective capacity resource was offered to other LSEs at market value and there was no interest.[16]

AReM, CAISO, Calpine, GenOn, Microsoft, MRP, WPTF, and Vistra oppose Energy Division's proposal and extending the effective PRM.[17] These parties generally are concerned that the effective PRM allows IOUs to procure non-RA resources that may be less reliable than RA resources because non-RA resources are not subject to CAISO's RA rules (such as the must-offer obligation and RAAIM), and that CAISO can only use the Capacity Procurement Mechanism (CPM) backstop authority to cure deficiencies for the binding PRM (not the effective PRM). These parties point out that Energy Division's proposal

[15] CESA Opening Comments at 2, Cal Advocates Opening Comments at 9, SCE Opening Comments at 2, CalWEA Reply Comments at 2, GPI Opening Comments at 1, CalCCA Opening Comments at 30, IEP Opening Comments at 3.

[16] AReM Opening Comments at 6.

[17] AReM Opening Comments at 6, CAISO Opening Comments at 4, CAISO Reply Comments at 2, Calpine Opening Comments at 1, GenOn Opening Comments at 8, Microsoft Opening Comments at 4, MRP Opening Comments at 7, WPTF Opening Comments at 2, Vistra Opening Comments at 16.

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would result in a PRM below the results of the LOLE study, which could significantly impact reliability. CAISO states that if the effective PRM is only applied to the summer months and the actual PRM is set below the 0.1 LOLE, reliability risk may surface in non-summer months.

SCE supports allocating effective PRM costs first to deficient LSEs before all LSEs and that deficient LSEs should pay for the costliest MWs that were procured for the effective PRM.[18] PG&E states that deficient LSEs should only be responsible for the increase in emergency procurement caused by the deficiency, not a greater share of the entire procurement.[19] PG&E states that if emergency procurement is used to make up for deficient LSEs, emergency procurement cannot increase reliability without increasing the level of IOUs' emergency procurement.

AReM and CalCCA oppose allocating effective PRM costs first to deficient LSEs.[20] AReM states that this would triple the LSEs' penalties, as they would be subject to Commission fines, CAISO backstop, and effective PRM costs, and that this is unfair considering an LSE's deficiency may have been partially caused by the effective PRM. CalCCA states that since the LSE could not procure resources used to meet the effective PRM to meet its RA requirement, it does not make sense to assign costs of the effective PRM to the deficient LSE.

CESA, Calpine, IEP, GenOn, MRP, Microsoft, and WPTF support a higher PRM with recommended ranges between 18-21 percent based on the LOLE study. Calpine and GenOn support an 18-20 percent PRM, WPTF supports at least an 18 percent PRM, and IEP and CESA recommend an 18 percent PRM with

[18] SCE Opening Comments at 3.

[19] PG&E Opening Comments at 3.

[20] AReM Opening Comments at 8, CalCCA Reply Comments at 3.

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retention of the effective PRM.[21] Microsoft recommends a 21 percent PRM based on the SERVM results indicating a 18-21 percent PRM will be needed for July-September. MRP recommends a 17.8 percent PRM based on the CEC-based September PRM plus 3.3 percent additional PRM to achieve 0.1 LOLE, or supports an 18-20 percent PRM.

CAISO states that the PRM should be higher than 17 percent to meet a 0.1 LOLE target.[22] However, CAISO states that it cannot conclude that an 18-20 percent PRM will meet a 0.1 reliability target because Energy Division's recommendation was between the PRM needs from the CEC and SERVM demand forecasts in summer months. AReM supports a 15.3 percent PRM, stating that the PRM should be calculated based on the CEC forecast and that for summer months, the PRM range based on the CEC forecast is 14.5-21.4 percent.[23] IEP disagrees and states that PRMs in the LOLE study are not monthly PRMs but are annual installed capacity needed to reach 0.1 LOLE divided by each month's peak load.[24]

Some parties argue that additional vetting of the LOLE study's inputs and assumptions is necessary. MRP and SCE generally state that the LOLE study is incompatible with the monthly RA program because it uses an annual rather than monthly portfolio such that the PRM results for most months are meaningless.[25] SCE recommends that future PRM studies match SOD resource

[21] CESA Opening Comments at 4, Calpine Opening Comments at 1, IEP Opening Comments at 2, GenOn Opening Comments at 4, MRP Opening Comments at 6, Microsoft Opening Comments at 3, WPTF Opening Comments at 2.

[22] CAISO Opening Comments at 4, CAISO Reply Comments at 2.

[23] AReM Opening Comments at 3.

[24] IEP Reply Comments at 1.

[25] MRP Opening Comments at 4, SCE Opening Comments at 4.

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counting and showing rules. Vistra states that Energy Division does not allow for the PRM to be updated on a recurring basis and appears to establish a probabilistic PRM for 2024 but a static PRM for 2025.[26] CAISO, MRP, and AReM state that additional testing is needed to ensure the PRM meets a 0.01 LOLE target, and more transparency is needed in the study process.[27]

CESA and MRP state that it is unclear whether there is a recommended PRM for the SOD framework.[28] MRP states that more discussion is needed to determine whether the SOD PRM range is compatible with the SOD framework. AReM states that further calibration of the portfolio may be needed on an hourly basis as loss of load events are concentrated in evening hours and applying the SOD PRM to every hour may overstate need outside of evening hours.[29]

4.3.3. Discussion

In considering the appropriate PRM for 2024 and beyond, Energy Division highlights the following challenges:[30]

- Because the CEC's load forecast (used to set RA requirements) increased significantly in 2021, the increased load forecast and increased PRM levels resulted in summer 2023 RA requirements that were 4-5 percent higher than the 2021 RA requirements. For summer 2024, a 17 percent PRM would result in requirements that are nearly 8 percent higher than 2021 requirements.

- Energy Division's LOLE study modeled a 2024 resource fleet that relies heavily on in-development capacity

[26] Vistra Opening Comments at 16.

[27] AReM Reply Comments at 10, MRP Opening Comments at 4, CAISO Opening Comments at 5.

[28] CESA Opening Comments at 5, MRP Opening Comments at 9.

[29] AReM Opening Comments at 5.

[30] Energy Division Phase 3 Proposals at 4.

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(5,823 MW of in-development resources). In recent years, development projects have experienced significant delays.

The Commission observes that while the majority of parties recognize the identified challenges, parties diverge as to the appropriate PRM to addressing the challenges. On the one hand, numerous parties support a binding PRM that meets a 0.1 LOLE reliability target based on the LOLE study and oppose extending the effective PRM, for the purpose of ensuring grid reliability. By contrast, other parties favor maintaining the status quo PRM and extending the effective PRM in order to balance the results of the LOLE study with the reality of available RA supply, for the purpose of ensuring grid reliability while avoiding RA shortages that may lead to excessive prices and costs to customers.

In recent years, development projects have faced significant delays due to a host of issues, including supply chain delays, labor shortages, interconnection queue limitations, and rising costs. The Commission is very concerned that a large portion of the over 5,800 MW of RA resources under development and modeled into the LOLE study will experience delays and be unavailable for the 2024 RA year. Adopting a higher PRM before there is certainty on installed RA resources will likely result in RA shortages that will unnecessarily inflate RA costs. A lack of sufficient RA resources with a higher PRM may result not only in LSE deficiencies, but in increased prices for all RA capacity as demand exceeds supply, and such an outcome will be detrimental to ratepayers.

The Commission agrees with parties that support extending the effective PRM through 2025. Extending the effective PRM is beneficial in that it provides non-binding targets for IOUs to procure contingency resources, including resources that are not subject to strict RA counting rules and resources that fewer entities are competing for, such as imports procured after the RA showing date

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and firm energy from co-generation facilities. This allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.

The Commission also agrees with parties that support retaining the status quo PRM of 17 percent as prudent for the 2024 and 2025 RA years given the realities of available RA supply and persistent delays in development projects. As mandated by Public Utilities (Pub. Util.) Code Section 380, the Commission's RA program must balance multiple objectives, including minimizing costs to ratepayers while ensuring grid reliability.[31] The Commission finds that increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time. There are 9,061 MW of new resources under contract for 2024.[32]Given the amount of new contracted resources and the ~470 MW increase in RA requirements associated with a 1 percent increase in the PRM, we find that the previously adopted 17 percent PRM for 2024 is reasonable.

The Commission finds it reasonable to maintain the effective PRM adopted in D.21-12-015 at the 2023 level for the 2024 and 2025 RA years. For 2023, the targeted procurement range of 2,000-3,000 MW, when added to a 16 percent PRM, results in an effective PRM of approximately 5-7.5 percent. Energy Division Staff estimates that the 2024 CPUC load forecast will be 42,700 MW. To maintain a similar target range with a 17 percent PRM, the effective PRM would

[31] All statutory references shall be to the Public Utilities Code, unless otherwise specified.

[32] Joint Agency Reliability Planning Assessment – SB 846 Quarterly Report and AB 205 Report, CEC-21-ESR-01, at 44, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/joint-agency-reliability-planning-assessment_20230209t155250.pdf.

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translate to 4-6.5 percent, or a range of 1,700-3,200 MW. Accordingly, for the 2024 and 2025 RA years, the Commission adopts a PRM requirement of 17 percent and adopts an effective PRM procurement target of 1,700-3,200 MW. The procurement targets will be divided between the three IOUs similar to the targets adopted in D.21-12-015, resulting in effective PRM targets of 170-320 MW for SDG&E, and 765-1,440 MW each for PG&E and SCE.

The requirements adopted in D.21-12-015 pertaining to the effective PRM are applicable to the effective PRM adopted in this decision. Specifically, the effective PRM will only apply for peak summer months (June–October) with IOUs permitted to use excess resources from existing portfolios to meet minimum target levels in June and October. Resources eligible to count towards the effective PRM will remain unchanged from D.21-12-015 and all resources that are currently eligible to be contingency resources will remain eligible to be contingency resources in 2024 and 2025. IOUs are reminded that their excess RA-eligible resources may be used towards the effective PRM targets, provided that the IOU has made reasonable attempts to sell the excess capacity to other LSEs, as provided in D.21-12-015.[33]

The Commission declines to assign costs for effective PRM procurement to deficient LSEs first. All costs associated with the effective PRM procurement will be assigned to all customers through the CAM, as adopted in D.21-12-015.

The Commission authorizes Energy Division to update and publish the LOLE study annually by February of each year with a baseline resource list published by November of the prior year. The Commission will continue to

[33] D.21-12-015 at Ordering Paragraph (OP) 72.

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monitor market conditions and impacts of the adopted PRM framework and will reevaluate the PRM requirements for the 2026 RA year in 2024.

Regarding the SOD framework, we stated in the Amended Scoping Memo:[34]

> The Implementation Track will consider modifications to the PRM for 2024 and beyond, which may include the recent 2024 LOLE study in IRP or a future LOLE study for RA to be submitted into this proceeding no later than January 2023. The Reform Track will consider how to convert/calibrate the results of a LOLE study to the slice-of-day RA framework.

As such, the PRM framework adopted here will apply to the 2024 test year for the SOD framework. As determined in D.22.06-050, and reiterated in D.23-04-010, the Commission will apply a single PRM to all hours of the year for initial implementation of the SOD framework.[35] We stated that we may consider whether multiple PRMs are appropriate for the SOD framework in a future phase of this proceeding.

Further, in D.23-04-010, the Commission determined that:

> Energy Division is authorized to integrate the Natural Resources Defense Council (NRDC) and Southern California Edison's (SCE) calibration tools to convert the results of the loss of load study to the 24-hour slice-of-day framework, to the extent possible. After Energy Division modifies the calibration tool, Energy Division is directed to publish the draft calibration tool on the Commission's website and solicit informal party comments.[36]

As such, the calibration tool will be modified by Energy Division, as directed in D.23-04-010, and Energy Division will use the results of the LOLE

[34] Amended Scoping Memo at 3, 5.

[35] D.23-04-010 at 59.

[36] D.23-04-010 at OP 13.

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study for the calibration. Energy Division will publish the results of the draft calibration tool on the Commission's website by September 2023, which will be followed by a workshop and an opportunity for informal party comment on the results of the calibration tool.

Several parties provide comments and critiques regarding the LOLE study's inputs and assumptions based on questions posed by Energy Division. The Commission notes that Energy Division considers these comments for future year studies and that parties are encouraged to participate in the process for applying inputs and assumptions, including participating in the Modeling Advisory Group.

Lastly, we note that AReM proposes multi-year forward obligations for system RA,[37] which a number of parties commented on. The Commission views this proposal as one of a number of ways of implementing a programmatic approach to reliability and clean power procurement that parties commented on in the IRP proceeding in December 2022 and January 2023. The Commission declines to consider a programmatic approach here and expects to engage with stakeholders in the IRP, RA, and Renewables Portfolio Standard (RPS) proceedings on this topic in the future.

4.4. Ambient Derating of Thermal Resources

Energy Division recommends a new method for derating thermal power plants based on forecasted ambient temperatures.[38] Energy Division states that the SERVM model - used to forecast energy prices and grid reliability - uses input capacities for thermal power plants that are "insensitive to environmental

[37] AReM Phase 3 Proposals at 4.

[38] Energy Division Proposal for Derating Thermal Power Plants based on Ambient Temperature (Energy Division Derate Proposal) at 2.

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factors – available capacities are assumed constant, unvaryingly equal to each plant's rated capacity and independent of ambient temperature."[39] Energy Division states that with a warming climate, the range of ambient temperatures under which generators operate are expected to increase, which may result in inconsistencies between actual operating conditions of power plants and modeled outcomes, potentially underestimating reliability risks.

Energy Division proposes a piecewise-linear relationship between ambient temperature and power capacity for a given power plant.[40] The model accounts for each power plant's tributary power sources and will be based on a correction factor which, when applied to a plant's rated power capacity, provides the approximate capacity available at an ambient temperature. The model applies to two unit types (Combustion Turbine and Combined Cycle resources) and uses historic weather data currently used in other SERVM inputs, with synthetic weather cases in future modeling.

4.4.1. Comments on Proposal

CalCCA, Cal Advocates, Microsoft, MRP, PG&E, and SDG&E point out that Energy Division's proposal does not extend to resource counting rules, which could create a mismatch between resource counting in the LOLE study and resource counting for compliance purposes.[41] These parties state that if ambient derates are applied to net qualifying capacities (NQC) for modeling and PRM analysis, derate adjustments should also apply to NQCs for compliance. PG&E and Calpine note that some plants already account for ambient derates in

[39] *Id*.

[40] *Id*. at 22.

[41] CalCCA Opening Comments at 32, Cal Advocates Opening Comments at 13, Microsoft Opening Comments at 9, MRP Reply Comments at 6, PG&E Opening Comments at 17, SDG&E Opening Comments at 6.

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their QC values, such as Calpine's combined cycle facilities, and Calpine states that this could lead to duplicative derating of some units.[42]

Calpine, PG&E, and SCE are concerned about Energy Division's use of CAISO's outage data.[43] Calpine notes that CAISO's data is incomplete because resources submit larger, overlapping outages that include ambient derates but are not recorded as such. SCE states that CAISO's data is reported ahead of the operational hour so that data is forecast rather than actual. PG&E states that CAISO's data used in calibrating the derate model includes outages for reasons other than ambient temperatures, and it is unclear whether the data was cleaned enough to isolate ambient derates.

IEP, MRP, WPTF, and Calpine oppose Energy Division's methodology as not robust enough for resource counting.[44] WPTF and Calpine state that the analysis ignores distinctions between different units and should be refined with more granular differentiation. Calpine and IEP express concern that the model excludes data for certain units, such as filtering out poorly fit resources, without a strong rationale. MRP states that the linear derate factors do not account for inlet cooling, as inlet cooling can counteract the effects of increased temperatures, so production capability does not decrease linearly with temperature.

GPI supports Energy Division's approach but is concerned that turbine manufacturer performance curves were not in the proposal.[45]

[42] PG&E Opening Comments at 17, Calpine Opening Comments at 6.

[43] SCE Opening Comments at 20, Calpine Opening Comments at 6, PG&E Opening Comments at 17.

[44] Calpine Opening Comments at 5, WPTF Opening Comments at 13, MRP Opening Comments at 16, IEP Opening Comments at 5.

[45] GPI Opening Comments at 4.

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SDG&E, Cal Advocates, and IEP generally support incorporating ambient derates into thermal resources' QC values and modeling.[46] CalCCA and IEP support development of an Unforced Capacity Evaluation (UCAP) methodology which would account for various forced outage types, including ambient derates.[47]

4.4.2. Discussion

The Commission finds there is insufficient record support for Energy Division's proposed methodology at this time. We agree with parties that support incorporating outages, including ambient derates, into a thermal resource's QC value and deem such work as critical to enhancing reliability. As stated in D.23-04-010, we agree with "explor[ing] a comprehensive application of UCAP to account for other types of forced outages, not just ambient derates."[48] Further, we recognized the limitations with CAISO's outage data and "encourage[d] CAISO to work through these data limitations to further develop a full UCAP mechanism for consideration in this proceeding."[49] In addition, the Commission encourages Energy Division to collaborate with CAISO on alternatives to using outage management system data to develop a UCAP mechanism.

4.5. LSE Expansion

Energy Division states that in recent years, there has been a significant increase in LSE deficiencies, with seven LSEs receiving month-ahead RA

[46] Cal Advocates Opening Comments at 6, SDG&E Opening Comments at 4, IEP Opening Comments at 6.

[47] CalCCA Opening Comments at 32, IEP Opening Comments at 6.

[48] D.23-04-010 at 41.

[49] *Id*.

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deficiencies in 2021 and five LSEs receiving month-ahead RA deficiencies in 2022.[50] Energy Division notes that despite the fact that some LSEs have not procured sufficient capacity to meet their RA requirements, some LSEs have sought to expand their customer territories. Energy Division is concerned that expansion by LSEs that have not met their RA requirements jeopardizes reliability but also results in leaning on LSEs that have met their full RA obligations. Further, Energy Division adds that if an effective PRM is adopted, persistent under-procurement of RA undermines the purpose of the effective PRM, which is intended to provide additional resources to respond to unexpected events. The effective PRM is not intended to backfill for LSEs that do not meet their existing RA obligations.

For these reasons, Energy Division proposes that "any CCA or ESP with a deficiency of greater than 2.5 percent of its system RA requirement on a month ahead RA filing during the previous two calendar years should not be able to expand and take on any new customer load for the following year."[51] Energy Division states that, for example, a CCA that had deficiencies in 2021 or 2022 would not be eligible to submit an Implementation Plan to expand to serve new service areas in 2023 for service in 2024.

4.5.1. Comments on Proposal

SDG&E, PG&E, and SCE support Energy Division's proposal.[52] PG&E contends that the proposal is consistent with D.21-06-033, which recommends

[50] Energy Division Phase 3 Proposals at 34.

[51] *Id.*

[52] SDG&E Opening Comments at 8, PG&E Opening Comments at 9, SCE Opening Comments at 18.

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against direct access expansion in part due to reliability impacts.[53] PG&E argues that allowing CCAs with a record of deficiencies to expand may result in planning uncertainty and adverse reliability impacts. PG&E asserts that the Commission has ample authority under Section 380 to set rules that would prevent any attempt by a deficient LSE to expand its service area.[54] SCE likewise argues that Section 380 gives the Commission broad discretion to ensure compliance by all LSEs.[55] SCE states that LSEs' failure to procure sufficient RA increases risks that the Provider of Last Resort (POLR) may have to take over procurement.

AReM, CalCCA, CCCE, SVCE, GPI and Shell oppose the proposal for a variety of reasons.[56] First, parties contend that the Commission does not have jurisdiction to make decisions about CCA and ESP formation. CalCCA and CCCE cite Assembly Bill (AB) 117 to illustrate that state governmental subdivisions and their residents, not the Commission, have authority to make decisions about CCA formation. CalCCA also asserts that Section 380 allows the Commission to enforce requirements over CCAs but does not extend authority over CCA formation or expansion. AReM states that Section 394(f) does not give the Commission authority over the contracting practices of ESPs.

CalCCA further contends that while Section 366.2(c)(8) allows the Commission to designate the effective date for a CCA's program, this may only be set after considering the impact of "any annual procurement plan of the

[53] PG&E Opening Comments at 9 (citing D.21-06-033 at 4).

[54] PG&E Reply Comments at 5.

[55] SCE Reply Comments at 6.

[56] GPI Opening Comments at 2, CalCCA Opening Comments at 19, AReM Opening Comments at 10, CCCE Opening Comments at 1, SVCE Opening Comments at 1, Shell Opening Comments at 2.

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electrical corporation that has been approved by the commission."[57] CalCCA states that an LSE's non-compliance with RA requirements has nothing to do with another LSE's procurement plan. PG&E disagrees and asserts that CalCCA disregards that expansion of service by a deficient CCA results in reduced RA procurement by the LSE that is losing those customers.[58] Thus, PG&E argues that Section 366.2(c)(8) allows the Commission to designate an effective date for a CCA implementation plan for a date after the CCA is in compliance with its RA requirements.

PG&E and SCE cite to D.05-12-041 for the proposition that the Commission's responsibility regarding CCA implementation plans includes "assur[ing] that the CCA's plans and program elements are consistent with … Commission rules designed to protect customers."[59] SCE points out that D.05-12-041 directed that the Commission "retain[s] a responsibility to assure that a CCA's policies, practices, and operations do not compromise the operations of the utility or services to utility customers."[60] SCE further states that the Commission approved SCE's Rule 23, which authorizes the Commission to terminate a CCA's service for cause if it fails to meet its LSE obligations.

Similarly, SCE argues that for ESPs, D.04-07-037 provided that: "[o]ur imposition of resource adequacy requirements on ESPs is a logical implementation of our jurisdiction to determine an ESP's operational capability

[57] CalCCA Opening Comments at 22.

[58] PG&E Reply Comments at 5.

[59] *Id*. at 7 (citing D.05-12-041 at 4), SCE Reply Comments at 4 (citing D.05-12-041 at 11).

[60] SCE Reply Comments at 4 (citing D.05-12-041 at 11).

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because adequacy of resources directly affects an ESP's capability to operate."[61] SCE argues that the Commission has authority to terminate an ESP's service for cause.

Second, CalCCA, AReM, Shell, and SVCE assert that Energy Division's proposal would result in discriminatory application of Section 380 because it would only apply to CCAs and ESPs and not IOUs that currently act as Providers of Last Resort.[62] Third, CalCCA and Shell state that the proposal is ambiguous.[63] CalCCA states that the use of the terms "any new load" and "new customers" are vague and overly broad, and Shell states it is unclear what is meant by prohibiting "expand[ing] and tak[ing] on any new customer load."[64] Shell adds that the proposal makes no distinction between compliance shortfalls due to lack of available system capacity, as opposed to individual LSE procurement failures. Shell also argues that the 2.5 percent threshold in Energy Division's proposal is not explained.

Lastly, SVCE argues that customers are entitled to aggregate load with members of the local community.[65] Thus, SVCE states that barring a CCA from serving new load would violate customers' rights to receive service from a CCA, eliminate the potential of new development in a CCA's service area, and conflict with a CCA's obligation to offer services to all residential customers within its jurisdiction.

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[61] *Id.*

[62] CalCCA Opening Comments at 23, AReM Opening Comments at 9, SVCE Opening Comments at 3, Shell Opening Comments at 4.

[63] CalCCA Opening Comments at 26, Shell Opening Comments at 5.

[64] Shell Opening Comments at 6.

[65] SVCE Opening Comments at 2.

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PG&E presents alternative options to address the concerns raised in Energy Division's proposal.[66] PG&E proposes a new fine for any LSE that expands its service territory but was deficient during the two prior years, at a sufficiently high level to prevent the LSE from expanding. PG&E also proposes reassigning any LSE that was deficient in the past two years and is pursuing expansion to the highest penalty tier (or new higher tier), making it too expensive for the LSE to expand.

4.5.2. Discussion

As has been documented in the RA proceeding, the acceleration of climate change with extreme, unpredictable weather events across the West has resulted in severe heat events, droughts, and wildfires. In the summers of 2021 and 2022, severe heat events resulted in significant stress on the grid that required California to rely on every available resource to prevent electric outages. Against this backdrop, the Commission is very concerned that an increasing number of LSEs have failed to meet their RA obligations in recent years. In D.21-06-029, the Commission modified the RA penalty structure to further discourage RA non-compliance by using a point accrual system that increased RA penalties where an LSE is repeatedly deficient in its RA obligations. Despite these efforts, the Commission has observed LSEs are continuing to fail to meet RA obligations, with seven LSEs receiving month-ahead system RA deficiencies in 2021 and five LSEs receiving month-ahead system RA deficiencies in 2022.[67] A portion of these LSEs have repeatedly failed to meet their RA obligations. Even more concerning, some LSEs submitted implementation plans to expand their

[66] PG&E Reply Comments at 7.

[67] Energy Division Phase 3 Proposals at 34.

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customer load by increasing their service territory, even as they have been unable to secure sufficient capacity to meet their RA obligations and serve their existing customers.

Section 380(a) provides that the "commission…shall establish resource adequacy requirements for all load serving entities." While the primary purpose of Section 380 is to "ensure the reliability of electric service in California"[68] by facilitating the development of new generation and retaining existing generating capacity that is economic and needed, the statute also seeks to equitably allocate costs among customers.[69] The duty to prevent cost shifting is echoed in Section 366.2(a)(4), which provides:

> The implementation of a community choice aggregation program shall not result in shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.

Section 366.2(a)(5) further makes clear that:

> A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers except where other generation procurement arrangements are expressly authorized by statute.

CalCCA and other parties argue that AB 117 did not confer authority on the Commission to determine whether a city, county, or joint powers authority forms a CCA or expands its scope. CalCCA further argues that "RA non-compliance by an LSE has nothing to do with a utility's procurement plan."[70] These arguments ignore that if one LSE fails to contract for resources to serve its

[68] Section 380(b).

[69] Section 380(b)(3).

[70] CalCCA Opening Comments at 22.

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own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.

AB 117, permitting the formation of CCAs, was adopted in 2002. In Decision 05-12-041, we implemented processes to permit CCAs to form and purchase power for their local residents and businesses. There, we acknowledged that the Commission "has the authority to exercise limited jurisdiction over non-utilities in furtherance of [our] regulation of public utilities, including resource adequacy."[71] We held that "[t]he utilities will not procure power on behalf of CCA customers as part of their resource adequacy planning."[72] This provision was codified in 2011, when the legislature added subdivisions (b)(4) and (5) to Section 366.2, clarifying that CCAs must prepare to fully supply electricity to their customers, and may not shift costs for energy to the customers of other LSEs by failing to contract in advance for such capacity. We further held that "[w]here continued CCA service…may substantially compromise utility operations or service to bundled customers," the Commission may authorize the utility to terminate a CCA's service.[73]

Energy Division's proposal is not a modification of D.05-12-041 but a new requirement under the umbrella of reliability and Resource Adequacy for CCAs planning to implement an expansion in their service territory or ESPs increasing their number of customers. The Commission agrees that allowing LSEs that cannot meet their existing RA obligations to expand their territory or to take on new customer load is detrimental to grid reliability. We also find that LSEs that

[71] D.05-12-041 at Conclusion of Law (COL) 2.

[72] *Id*. at COL 19.

[73] *Id*. at COL 55.

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are deficient in their RA obligations result in leaning on other LSEs' procurement activities, and impairing grid reliability by failing to secure resources to support their existing customer base. The Commission has authority to approve Energy Division's proposal to ensure that LSEs procure sufficient capacity to meet their customer loads, maintain electrical grid reliability, and prevent deficient LSEs from increasing risk of grid emergencies arising from lack of resources bidding into CAISO's wholesale markets. As provided in Resolution E-4907, establishing the registration process for CCAs, we acknowledge our authority to approve the effective date for a CCA to implement a planned expansion[74] and here, we ensure that such planning accounts for a CCA's history of recent RA deficiencies demonstrating the CCA's inability to procure resources to serve its existing customers.

Some parties observe that in D.05-12-041, the Commission stated that AB 117 does not give the Commission "authority to approve or reject a CCA's implementation plan or to decertify a CCA."[75] Here, we do not consider rejecting a CCA's expansion plan or decertifying a CCA. Rather, Energy Division's proposal seeks to ensure LSEs do not plan to expand load until they demonstrate they are capable of procuring to meet their existing customer needs. The Commission finds this to be a reasonable, measured approach to enforcing the Public Utilities Code, including Section 380, to ensure grid reliability through Resource Adequacy compliance.

We also disagree with arguments that Energy Division's proposal would violate Section 380's requirement that the Commission enforce the RA

[74] *See* Resolution E-4907, Registration Process for Community Choice Aggregators, February 9, 2018.

[75] D.05-12-041 at 4.

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requirements "in a nondiscriminatory manner." The Public Utilities Code creates a variety of distinctions between different classes of LSEs as, for example, the IOUs are currently serving as the Providers of Last Resort (POLR), while CCAs and ESPs are permitted to return their customers. It is not discriminatory for our rules to reflect statutory legal distinctions. As discussed above, a CCA that fails to meet its RA requirements is leaning on the procurement of other CCAs that have met their procurement requirements to support grid reliability. Thus, some CCA customers may benefit from this proposal by avoiding reliability problems caused by other LSEs' failures to procure resources.

For these reasons, we find Energy Division's proposal, with modifications discussed below, to be a reasonable approach and permissible under Pub. Util. Code Section 380. This requirement should apply to any LSE with the exception of the POLR, as the POLR is mandated by Section 387 to serve load if other LSEs fail to provide service or "otherwise meet its obligations."[76]

Some parties seek clarification regarding whether Energy Division's proposal would prevent CCAs from serving load in newly developed areas within the existing CCA territory or where customers move into the CCA territory. We clarify that the limit on expansion only applies to a CCA's plans to expand its service territory, and not to new developments within a CCA territory or customers moving into the CCA territory. Thus, new customers in a CCA's existing territory may be defaulted into the CCA's service but the CCA is not permitted to submit an implementation plan to expand to incorporate new territory. As applied to an ESP, existing customers may experience load expansion, relocation, and changes in their service accounts, including adding

[76] Section 387(a)(3).

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new accounts from the ESP's existing customers. However, the limit on expansion means the ESP is not permitted to sign new customers into its service, including taking on new customers switching from another ESP or entering the direct access program from an IOU or CCA's service via the direct access lottery.

The Commission declines to adopt the proposed 2.5 percent threshold for RA deficiencies but determines that a 1 percent minimum threshold is reasonable, similar to that adopted in D.21-06-029 for the penalty point structure. Therefore, an LSE's system deficiency of 1 percent or greater will be applicable to the expansion requirement adopted here.

The Commission agrees (with some caveats) that if an LSE "cures" its year-ahead RA deficiency in the month-ahead timeframe, the year-ahead deficiency will not be applied to the expansion requirement. However, this only applies to a year-ahead deficiency accrued two years before the year in which the LSE files its binding load forecast. To illustrate, Year 0 (Y0) is the year that an LSE files its binding load forecast with additional load it will serve. An LSE must meet its year-ahead and month-ahead requirements in the two years before Y0 (that is, Year Minus 1 (Y-1) and Year Minus 2 (Y-2)). If an LSE receives a year-ahead deficiency in Y-2 and "cures" that deficiency in the month-ahead process in Y-1, the Y-2 deficiency will not apply to the expansion requirement. A year-ahead deficiency in Y-1, however, will necessarily apply to the expansion requirement because there is insufficient time for the LSE to cure the Y-1 deficiency in the Y0 month-ahead timeframe, as the LSE will have filed its binding load forecast commitments. The applicable system RA deficiencies are depicted in the table below.

Accordingly, a CCA that has had system RA deficiencies within the prior two calendar years must first be in RA compliance for two calendar years prior

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to submitting an implementation plan to expand. An ESP that has had system RA deficiencies within the prior two calendar years must first be in RA compliance for two calendar years prior to signing new direct access customers. These rules are applicable to LSEs that are not acting as the POLR. As to CCAs, this requirement will apply to initial or revised implementation plans submitted after the effective date of this decision. As to ESPs, this requirement will apply to direct access customers signed after the effective date of this decision.

In other words, an LSE's eligibility to sign new direct access customers or to submit an implementation plan to expand its service territory will be contingent on compliance with RA requirements for the prior two calendar years. RA deficiencies accrued after the effective date of this decision will be used to calculate the potential expansion pause period. The first year-ahead deficiencies to be applied will be the 2024 year-ahead RA filing due on October 31, 2023, and the first month-ahead deficiency to be applied will be the September 2023 month-ahead RA filing.

The following system RA deficiencies will apply to the LSE expansion requirement:

System RA Deficiencies That Apply to the LSE Expansion Requirement	
Year Plus 1 (Y+1)	Year that an LSE elects to expand
Year 0 (Y0)	Year that an LSE files its April load forecast
Year Minus 1 (Y-1)	(1) Month-Ahead deficiencies apply (2) Year-Ahead deficiency (for Y0) applies *Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1.
Year Minus 2 (Y-2)	(1) Month-Ahead deficiencies apply

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	(2) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1

Substantive month-ahead and year-ahead system RA deficiencies will apply to the expansion rule. The following violations will not count towards the expansion requirement:

(1) A month-ahead or year-ahead system RA deficiency that is less than 1 percent of the LSE's system RA requirements.
(2) "Specified violations," as adopted in Resolutions E-4017 and E-4195 and modified in D.11-06-022.

To implement the adopted requirement, Energy Division is authorized to review RA enforcement referrals or citations issued by CPED, including confidential versions, for the prior two calendar years to determine if an LSE is eligible to expand. Energy Division will review and confirm compliance with the requirement ahead of the LSE's RA load forecast submissions, confirm the earliest possible effective date for the CCA expansion by letter from the Executive Director, and inform the CEC of any adjustments to the load forecast necessary due to non-compliance. Energy Division is authorized to make this determination regardless of any pending citation appeal.

4.6. CPE Requirements

4.6.1. Transparency and Reporting

Energy Division and CalCCA each propose additional reporting requirements for the CPEs to submit in their compliance filings and Annual Compliance Reports (ACR). Energy Division recommends that the August compliance filing and the September ACR each should include:[77]

[77] Energy Division Phase 3 Proposals at 31.

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(1) Monthly MW amounts of deferred procurement that were the result of unreasonable prices over the compliance period;

(2) Monthly MW amounts of procurement not offered to the CPE in deficient areas over the compliance period;

(3) Monthly MW amounts of procurement offered in and later withdrawn over the compliance period; and

(4) Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcomes of the outreach.

Energy Division also recommends that the CPEs provide the following:

Monthly Procurement Summary Covering All CPE Procurement					
Total CPUC Local Allocation (excluding DR)	Total CPUC-allocated Local DR	Local CAM (non-DR)	Total Procured Resources	Total Self-Shown	Net Total

Energy Division seeks to publish this information on the Commission's website and states that the additional data would help LSEs manage upfront system RA procurement and assess the potential for backstop procurement. This would assist LSEs in understanding the inventory of available resources in the market.

CalCCA recommends additional data reporting to provide a more comprehensive view of CPE procurement efforts and recommends the following be submitted in the ACRs:[78]

(1) If any offers or self-showings were not selected by the CPE, why were they not selected (price, inability to negotiate contract terms, other); and

(2) Total NQC of local RA not offered or self-shown.

[78] CalCCA Phase 3 Proposals at 11.

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Parties that support Energy Division's proposal include Cal Advocates, CAISO, GPI, Joint Environmental Parties, Shell, Vistra, WPTF, and PG&E (with modifications).[79] Joint Environmental Parties also request that the CPEs report on why LSEs are electing not to self-show. PG&E supports the additional reporting and recommends that the confidentiality matrix adopted in D.22-03-034 be modified to indicate the confidentiality status of the new requirements. PG&E suggests modifying the monthly MW amounts, as proposed by Energy Division, to protect market-sensitive information from the CPE's solicitation process, as follows:

a. Total aggregate monthly MW amount of procurement not offered to the CPE in deficient areas;
b. Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and
c. Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

SCE opposes Energy Division's proposal to include aggregated resources that did not participate in the solicitations, or to conduct outreach to determine the reasons for lack of participation.[80] SCE states that the CPE does not have

[79] Cal Advocates Opening Comments at 10, WPTF Opening Comments at 11, Shell Opening Comments at 11, Joint Environmental Parties Opening Comments at 2, MRP Opening Comments at 19, Vistra Opening Comments at 23, CAISO Opening Comments at 10, PG&E Opening Comments at 5.

[80] SCE Opening Comments at 13.

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visibility into which resources did not participate, including which resources will be coming online.[81] SCE does not object to other reporting so long as market-sensitive information remains confidential, and supports including confidential information in the ACR if it is not disclosed to market participants. SCE states that providing aggregated resources that were not selected due to high prices does not provide LSEs with information to help manage procurement, and pricing is market-sensitive information.

CalCCA disagrees with SCE and states that the CPE can use the NQC list that provides which RA resources are online or under development to determine which resources were not offered or self-shown.[82] CalCCA states that providing information on why resources were not selected to market participants would help LSEs understand how the CPE framework is functioning, including sources of any CPE deficiencies. CalCCA argues that the information is not market-sensitive because the CPEs would report it at an aggregated level according to the reasons for non-selection, and not publicize price information.

Parties that support CalCCA's proposals include Cal Advocates, WPTF, Shell, Joint Environmental Parties, Vistra, and GPI.[83] SCE opposes CalCCA's proposal to require CPEs to explain why offers or self-showings were not accepted or why LSEs did not submit offers.[84] PG&E states that its modifications to Energy Division's proposal would similarly cover CalCCA's request for NQCs

[81] SCE Reply Comments at 2.

[82] CalCCA Reply Comments at 4.

[83] Cal Advocates Opening Comments at 10, WPTF Opening Comments at 11, Shell Opening Comments at 11, Joint Environmental Parties Opening Comments at 2, MRP Opening Comments at 19, Vistra Opening Comments at 23, GPI Reply Comments at 2.

[84] SCE Opening Comments at 13.

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of local RA not offered or self-shown and why an offer or self-showing was not selected by the CPE.[85]

4.6.1.2. Discussion

The Commission agrees with the numerous parties that support additional data reporting by the CPE both to help LSEs manage upfront system RA procurement and to understand the inventory of available resources in the market in order to assess the potential for CAISO backstop procurement. We find that additional transparency in the CPE process would help market participants understand how the CPE framework is functioning. That said, we also agree that the additional data reporting should be aggregated in a way that does not disclose confidential, market-sensitive information.

To that end, we find Energy Division's proposal, with PG&E's modifications, to be appropriate additional data reporting by the CPE for the ACRs. With respect to the aggregate amounts of resources that were not offered to the CPEs, the CPEs should base this information by comparing the NQC list with the resources that bid into the CPE solicitation.

We clarify that the additional reporting does not require the CPE to survey or conduct outreach to LSEs as to the reasons for their lack of participation in the CPE solicitation. The "additional information" category is intended for the CPE to disclose any additional information it may be aware of as to resources that did not participate and/or withdrew their bids. In D.22-03-034, the Commission directed that an LSE that declined to self-show or bid a resource into the CPE solicitation shall file a justification statement with its year-ahead RA filing

[85] PG&E Opening Comments at 7.

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explaining the LSE's rationale.[86] In that decision, we declined to make LSEs' justification statements public but authorized Energy Division to include an assessment of the statements in their 2024 report.[87]

Accordingly, the CPEs shall report the following in both (a) the mid-August compliance filings and (b) the September ACRs:

Monthly Procurement Summary Covering All CPE Procurement					
Total CPUC Local Allocation (excluding DR)	Total CPUC-allocated Local DR	Local CAM (non-DR)	Total Procured Resources	Total Self-Shown	Net Total

a. Total aggregate monthly MW amount of procurement not offered to the CPE in deficient areas;

b. Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and

c. Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

Appendix A of D.22-03-034 is modified for consistency with the new reporting requirements to add the following.

Competitive Solicitation Information	Individual/ Specific Bid/Offer data	Confidential	3 years after conclusion	Disclosure of the bid/offer data received during CPE procurement could potentially have an adverse effect on the market, put the CPE at

[86] D.22-03-034 at OP 6.

[87] *Id*. at 47.

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			of solicitation	a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured.
Competitive Solicitation Information	Aggregate Bid/Offer Data Not Selected/Procured (where the total exceeds 10 MWs)	Public	N/A	N/A

A modified version of the confidentiality matrix adopted in D.22-03-034 is attached as Appendix A to this decision.

4.6.2. CPE Process Modifications

WPTF states that while D.22-03-034 directed Energy Division to review the CPE framework's effectiveness in a 2024 report, specific timing of the report's issuance was not established.[88] WPTF recommends that Energy Division's report be issued in January 2024, and a review process with party proposals and comments be established. WPTF further suggests that Energy Division's report address a series of questions, including whether the CPE framework has been cost-effective, has enhanced reliability, and has been efficient.

WPTF further recommends that LSEs that have self-shown resources to the CPE be allowed to sell the system and/or flexible attributes of those resources that are in excess of their individual local capacity obligation to other LSEs.[89] The purchasing LSE would assume the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system and/or flexible RA needs, as designated in D.22-02-034 at Ordering Paragraph (OP) 2. WPTF states that

[88] WPTF Phase 3 Proposals at 4.

[89] *Id*. at 6.

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this would improve market liquidity and LSEs' ability to meet system and flexible RA obligations. WPTF posits that this would potentially increase the amount of shown RA, as it removes a disincentive to self-show for LSEs that have excess system and flexible RA for local resources they own. WPTF adds that the purchasing LSE can submit an affidavit that states that: (a) the purchasing LSE will be bound by the requirement to show the resource on its RA plans, or (b) require the purchasing LSE to execute an addendum to the affidavit that affirms the resource will be shown on their RA plans.

IEP, MRP, and Shell support the proposal to allow LSEs to sell system and/or flexible RA attributes associated with self-shown local capacity.[90] PG&E does not offer comments on the proposal but asserts that it does not support the unbundling of RA products.[91] CESA, MRP, and Joint Environmental Parties support a clear timeline for reviewing the CPE framework.[92]

4.6.2.1. Discussion

The Commission agrees that direction on the timing of Energy Division's CPE report is warranted and finds it reasonable for Energy Division to submit the CPE report in Q1 of 2024. Following the issuance of the report, parties will have an opportunity to submit comments on the report.

Under the current framework, LSEs may decline to self-show a local resource to the CPE in order to retain the option to sell the capacity. We agree that allowing LSEs to sell the self-shown resource may increase the amount of self-shown resources by removing a potential disincentive for self-showing and

[90] IEP Opening Comments at 11, MRP Opening Comments at 20, Shell Opening Comments at 9.

[91] PG&E Reply Comments at 15.

[92] CESA Opening Comments at 6, Joint Environmental Parties Opening Comments at 3, MRP Opening Comments at 19.

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provide additional opportunities for LSEs to procure system and/or flexible RA. Therefore, we find WPTF's proposal to be reasonable so long as the purchasing LSE assumes the selling LSE's self-showing obligation. This would not allow unbundling of a resource since the LSE is selling both the local and system attribute, the local attribute must be shown to the CPE, and the local attribute stays with the CPE.

Accordingly, an LSE that has self-shown a local resource to the CPE is permitted to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system and/or flexible RA needs, as required by OP 2 or D.22-02-034.

The Commission also finds it appropriate to modify the self-showing attestation for an LSE that sells its self-shown resource to another LSE. As adopted in D.22-03-034, an LSE that elects to self-show a local resource to the CPE must execute an attestation that provides that:[93]

(a) The LSE has the capacity rights to the RA resource for the period it is self-showing;

(b) The LSE intends to self-show the RA resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs; and

(c) If applicable, the resource that the LSE intends to self-show for compensation under the Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) meets the eligibility requirements pursuant to D.20-12-006.

[93] D.23-03-034 at OP 2.

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For any LSE that has self-shown a local resource to the CPE, and subsequently sells the capacity to another LSE, the selling LSE shall modify its attestation to provide that:

(a) The LSE has sold the capacity to another LSE, and the purchasing LSE will self-show the RA resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs as required by OP 2 of D.22-02-034; and
(b) If applicable, the resource that the LSE intends to self-show for compensation under the LCR RCM meets the eligibility requirements pursuant to D.20-12-006.

The modified attestation shall be provided to the CPE within 30 days of the purchase. Additionally, the purchasing LSE shall provide an attestation that it intends to self-show the capacity to the CPE within 30 days of the purchase.

Lastly, several parties put forth proposals for larger modifications to the CPE framework, such as CalCCA's proposal to lock in CPE procurement two years in advance,[94] MRP's proposal to allow CPE-procured capacity to be sold to LSEs and converted to self-shown capacity,[95] and Vistra's proposal for a CPE soft price cap to guide what constitutes high pricing.[96] The Commission defers consideration of larger changes to the CPE framework until after Energy Division's evaluation of the effectiveness of the CPE framework in 2024, as discussed above and adopted in OP 21 of D.22-03-034.

4.7. RA Import Requirements

4.7.1. Modifications to Import Requirements

In D.20-06-028, the Commission required that a non-resource-specific import shall count towards RA requirements, provided that:

[94] CalCCA Phase 3 Proposals at 8.

[95] MRP Phase 3 Proposals at 3.

[96] Vistra Phase 3 Proposals at 18.

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(a) The contract is an energy contract with no economic curtailment provisions;

(b) The energy must self-schedule (or in the alternative, bid in at a level between negative $150/MWh and $0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the Maximum Cumulative Capacity (MCC) buckets.

(c) The energy must be delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.[97]

Energy Division states that "a number of load serving entities are structuring these non-resource specific imports as RA capacity contracts, not energy contracts, with the resource being bid into the CAISO, rather than delivered to meet the energy needs of the load serving entity."[98] Energy Division states that because the LSE is not the scheduling coordinator (SC) for the resource, it is more difficult to assess penalties to the LSE for failure to meet the requirements of D.20-06-028.

Energy Division proposes that the LSE must be the scheduling coordinator for the non-resource-specific RA import to ensure that the LSE is responsible for the Commission's requirements. Energy Division also requests consideration of whether the self-schedule or bid at $0 to negative $150/MWh should be replaced with an energy must-flow requirement to ensure that energy contracts are not speculative and to ensure grid reliability.

CalCCA states that the current rules have dampened interest in selling RA imports to California LSEs and therefore, CalCCA proposes that that a maximum

[97] D.20-06-028 at OP 2.

[98] Energy Division Phase 3 Proposals at 37.

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import RA bid price should be based on the costs of the typical marginal resource in the market and the resource typically on margin during the AAH window is a Combustion Turbine.[99] Each element of costs, including heat rate, gas prices, variable operations and maintenance, and greenhouse gas (GHG) emissions, could be calculated to form tiers to determine resources' bids for each month. CalCCA recommends the following bid caps for gas prices up to: (1) $10/MMBTU = $143/MWh; (2) $20/MMBTU - $263/MWh; (3) $30/MMBTU or higher = $383/ MWh. CalCCA states that maximum bid prices would allow generators outside of California to economically bid resources and ensure bid prices are not so high as to be unlikely to be selected.

4.7.1.1. Comments on Proposals

AReM, BPA, CAISO, CalCCA, DMM, SCE, Vistra, and WPTF oppose requiring the LSE to be the SC.[100] These parties generally state that many LSEs cannot act as their own SC (due to size and operation costs), that this would be disruptive to business practices, and that this may increase costs to LSEs. MRP supports requiring LSEs to be the SCs.[101]

Some parties suggest alternatives to address Energy Division's concerns. AReM recommends that LSEs identify who their SC is in their RA showings to allow Energy Division to verify the import RA transaction.[102] CalCCA agrees with this proposal but clarifies that it is the SC associated with the import RA,

[99] CalCCA Phase 3 Proposals at 14, 22.

[100] AReM Opening Comments at 13, BPA Opening Comments at 3, CalCCA Opening Comments at 28, DMM Opening Comments at 5, Vistra Opening Comments at 26, SCE Opening Comments at 19, WPTF Opening Comments at 15, CAISO Reply Comments at 6.

[101] MRP Opening Comments at 15.

[102] AReM Opening Comments at 13.

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not other scheduled resources.[103] DMM and PG&E suggest that a CAISO resource ID associated with out-of-state resources could include the LSE ID for each LSE's share of the RA associated with the resource when the resource is scheduled/bid into the CAISO market.[104] DMM adds that each LSE could have its own scheduling coordinator ID that the third-party SC could use for imports under contract to that LSE.

AReM, CalCCA, SCE, WPTF, CAISO, MRP, and BPA oppose replacing the self-schedule or bid requirement with a must-flow requirement.[105] Several parties state that this could reduce willingness to transact with California LSEs and would limit an already tight RA market. AReM argues that there is no evidence why the current requirements are insufficient, noting that CAISO reported 99.96 percent of all RA static import capacity bid with either self-schedule or economic bids at or below $0/MWh in September 2022. BPA states it is unclear how the proposal would increase reliability of import deliveries. DMM seeks clarity on what a must-flow requirement would entail and finds it unclear if contracts would have to increase incentives for a supplier to deliver energy when the import receives a market award.[106]

AReM, DMM, Shell, IEP, MRP, and Vistra support CalCCA's proposal.[107] DMM and MRP state that suppliers would still expect to receive a CAISO import

[103] CalCCA Reply Comments at 7.

[104] DMM Opening Comments at 5, PG&E Opening Comments at 10.

[105] AReM Opening Comments at 14, BPA Opening Comments at 3, CalCCA Opening Comments at 28, SCE Opening Comments at 19, WPTF Opening Comments at 15, CAISO Reply Comments at 6, MRP Opening Comments at 15.

[106] DMM Opening Comments at 6.

[107] AReM Opening Comments at 14, DMM Opening Comments at 8, Shell Opening Comments at 10, Vistra Opening Comments at 26, IEP Opening Comments at 12, MRP Opening Comments at 15.

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schedule except during times of relatively low market prices, and this would provide the same reliability benefits as the current bid/self-schedule requirement. DMM does not recommend a particular bid cap but finds value in a bid cap over $0/MWh, but low enough for suppliers to expect an import schedule. IEP states that the proposal would dissuade speculative RA because the bid caps are pegged to market conditions.

PG&E opposes CalCCA's proposal and states that it is unclear it will increase overall import volume, as increasing the amount that can be recovered through the energy market would reduce the amount that needs to be recovered through the RA program.[108] Thus, while this may reduce the price of RA imports, PG&E states that it will not necessarily increase supply.

4.7.1.2. Discussion

The Commission finds insufficient record to replace the current RA import rules with a must-flow energy requirement or a maximum import RA bid price. We agree with AReM that there is no information as to why the current requirements are insufficient. Likewise, there is insufficient information to determine whether CalCCA's proposal would necessarily increase the volume of imports, rather than merely reducing the price of imports. Should information arise as to why the current RA import bidding requirements warrant modification, Energy Division Staff should present that information to the Commission and stakeholders for consideration.

The Commission recognizes that Energy Division is concerned that some non-resource specific RA imports are not satisfying the RA import requirements established in D.20-06-028. Energy Division cannot confirm in all instances

[108] PG&E Opening Comments at 11.

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which LSE is associated with an RA import when the LSE is not the scheduling coordinator for that import, and therefore, which LSE may be subject to penalties in the event of non-compliance. We agree with parties that state that requiring an LSE to be their own SC to address this concern would be overly burdensome on LSEs. In considering comments on the proposed decision, the Commission declines to adopt a proposal at this time. The Commission authorizes Energy Division to work with CAISO to identify the appropriate resource ID registration process that will allow non-resource specific RA import IDs to be mapped to the contracted LSE, when the LSE is not the scheduling coordinator. Energy Division should also investigate the real-time market reliability and liquidity concerns raised by parties in comments on the proposed decision, and submit a proposal into the RA proceeding as warranted.

4.7.2. Available Transmission Capability

CAISO is currently developing rules for wheeling transactions (as part of its Transmission Service and Market Scheduling Priorities (TSMSP) stakeholder process) that would allow non-CAISO LSEs to reserve available transmission capability (ATC) across the CAISO system based on historical RA usage in the 13-month ahead timeframe and based on actual usage in the monthly and daily timeframe at each particular intertie location.[109] Energy Division states that the high priority wheels would be given priority equal to CAISO load, if CAISO is unable to serve its own load, and allow for wheeling across its transmission system. CAISO does not propose that CAISO LSEs could buy the ATC in the 13-month ahead timeframe or monthly timeframe; however, CAISO proposes to allow those with high priority wheeling rights to sell those rights to others.

[109] Energy Division Phase 3 Proposals at 38.

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Energy Division notes that Commission rules only allow Commission-jurisdictional entities to pair RA imports with maximum import capability (MIC) allocations, and therefore, RA imports paired with ATC would not count towards RA obligations. Energy Division proposes that if a Commission-jurisdictional LSE procures ATC or acquires it through the resale process, the LSE should be allowed to pair the ATC with RA imports to meet RA requirements. Alternatively, Energy Division proposes to remove the MIC requirement for RA imports (which restricts the RA imports that entities can buy at each of the interties) since MIC does not currently convey deliverability.

SDG&E supports Energy Division's proposals and states that either proposal could address the concerns with CAISO's ATC proposal.[110] Shell states that Energy Division's first proposal, to allow ATC to be paired with RA imports to count towards RA requirements, is a good first step and should be further evaluated.[111]

CAISO and DMM oppose Energy Division's proposals.[112] CAISO states that MIC and deliverability concepts are subject to the CAISO tariff, and changes would require a stakeholder process. CAISO comments that its TSMSP proposal accounts for native load needs and includes additional margin in the calculations before releasing ATC to non-CAISO LSEs. CAISO adds that ATC is not a substitute for MIC and ATC does not represent simultaneous import capability deliverable to the CAISO load. CAISO states that its tariff requires LSEs to pair MIC with imports when shown as RA to ensure RA imports will be deliverable to the aggregate load along with internal generation. CAISO states that allowing

[110] SDG&E Opening Comments at 7.

[111] Shell Opening Comments at 7.

[112] CAISO Opening Comments at 13, DMM Reply Comments at 2.

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LSEs to use ATCs to show RA imports would conflate the MIC process for imports with the ATC process for external parties to support wheels across CAISO.[113] CAISO notes that it is open to reviewing its MIC design to ensure LSEs can transact for allocated intertie capacity to the maximum extent possible.

DMM agrees with CAISO that allowing ATC to meet RA import requirements could exacerbate the reliability risks of CAISO's TSMSP proposal.[114] DMM states that CAISO should consider internal transmission needs of native load as it implements its proposal and cautions against removing the MIC requirement for RA imports without more consideration as this could require other rules to ensure CAISO's balancing authority area is not counting on more import RA than possible.[115]

The Commission agrees with Energy Division's and parties' concerns about the uncertainty posed by the TSMSP proposal and that CAISO LSEs are disadvantaged in being unable to acquire available import capability to meet their RA needs. Thus, the Commission finds Energy Division's first proposal to be reasonable. That said, we recognize CAISO's concern that this could potentially result in a violation of the simultaneous import capability.

One way to address this is to limit the ability to acquire additional import capability through the ATC process to the two import locations most used by LSEs to pair with import RA: California-Oregon Border (COB)/Malin and Nevada-Oregon Border (NOB). By limiting the additional acquisition of ATC to these two interties, this would effectively ensure that there is no violation of the simultaneous import limit, nor any associated reliability risk. For this reason, we

[113] CAISO Reply Comments at 5.

[114] DMM Reply Comments at 2.

[115] DMM Opening Comments at 10.

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find this modification to Energy Division's proposal to be reasonable, and adopt it here. We also direct Energy Division Staff to work with CAISO on concerns that CAISO's penalty parameters do not sufficiently prioritize RA imports and that MIC does not reserve internal transmission for RA imports.

Accordingly, if a Commission-jurisdictional LSE procures ATC or acquires ATC through the resale process at either COB/Malin or NOB, the LSE is permitted to pair the ATC with RA imports to meet its RA requirements.

4.8. Compliance and Penalty Procedures

Below we address several proposals on the RA compliance and penalty processes.

4.8.1. Penalty Point System

In D.21-06-029, the Commission adopted a point system and tiered penalty structure for system RA deficiencies, as follows:[116]

Months	Points for Each Instance of System RA Deficiency
Non-Summer (November – April)	1
Summer (May – October)	2

Tier	Accrued Points	System RA Penalty Price
1	0-5	Applicable system RA penalty price
2	6-10	2x the applicable system RA penalty price
3	11+	3x the applicable system RA penalty price

Energy Division clarifies that the penalty price corresponding to an LSE's tier will apply to all penalties accrued by the LSE, including year-ahead penalties.[117] Energy Division cites the example that if an LSE is in Tier 2, the LSE

[116] D.21-06-029 at OP 16.

[117] Energy Division Phase 3 Proposals at 26.

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would be required to pay 2x the system penalty price for any year-ahead or month-ahead deficiency.

Energy Division also proposes that if the LSE enters a higher tier in a year that it had year-ahead deficiencies, the higher penalty should apply beginning with the monthly deficiency when the LSE enters the higher tier. Energy Division cites the example of an LSE with year-ahead deficiencies for May to September, and the same deficiencies for May to September in the month-ahead process. The LSE would pay the year-ahead penalty, and accrue two points for month-ahead May and two points for month-ahead June, totaling four points. The LSE would pay no additional penalties for month-ahead May and June, as it remains in Tier 1. However, the LSE would accrue two points for the month-ahead July deficiency, bringing the total to six points and raising the LSE's penalty price to Tier 2. For the month-ahead July penalty, Energy Division states that the LSE would pay the difference between the 2x system RA penalty for July and the year-ahead penalty price for July, and the Tier 2 penalty for any additional deficiencies. Energy Division further proposes that when an LSE accrues points that bring it to the next tier, the higher penalty should apply in the deficient month for which the points are accrued. Energy Division recommends that these changes apply to 2023 RA compliance.

SCE supports Energy Division's clarifications as reasonable and states that the proposal provides certainty to LSEs.[118] AReM, CalCCA, and CCCE oppose Energy Division's proposal.[119] AReM states that the proposal is punitive and that assessing points on year-ahead deficiencies lengthens the time LSEs hold

[118] SCE Opening Comments at 13.

[119] AReM Opening Comments at 8, CCCE Opening Comments at 3, CalCCA Opening Comments at 15.

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penalty points, as the points do not expire until 24 months after the violation. CCCE states that the proposal retroactively applies a higher price for a new tier to year-ahead deficiencies. CalCCA states that points should no longer be applied to LSE deficiencies for LSEs that demonstrate they took reasonable efforts to comply.

In adopting the penalty point system in D.21-06-029, the Commission stated that "[p]oints shall only be accrued for month-ahead deficiencies, not year-ahead deficiencies."[120] While points are only accrued for month-ahead deficiencies, the Commission did not state or intend that points are only applied to month-ahead deficiency penalties. We agree, therefore, that clarification is necessary that any points accrued by an LSE shall be applied to the LSE's month-ahead and year-ahead RA penalties. We note that the application of points apply to going-forward deficiencies, not applied retroactively. As provided in D.21-06-029, points shall expire 24 months after the violation.

The Commission also agrees that if an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier. For example, if an LSE has year-ahead deficiencies and accrues Tier 2 points in the month-ahead process for July, the LSE will pay the difference between the 2x system RA penalty for July and the year-ahead penalty price for July, and the Tier 2 penalty for any additional deficiencies. Likewise, we agree that the month in which an LSE accrues points that bring it into the next tier, the higher penalty shall apply to the deficient month for which the points were accrued. For example, if an LSE has month-ahead deficiencies for June and July, and the July

[120] D.21-06-029 at OP 16.

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deficiency results in points that would bring the LSE into Tier 2, the Tier 2 multiplier would apply to the month-ahead July deficiency penalty.

Accordingly, penalty points accrued by an LSE shall be applied to an LSE's month-ahead and/or year-ahead RA penalties. If an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier. The month in which an LSE accrues points that bring the LSE into the next tier, the higher penalty shall apply to the deficient month for which the points were accrued.

In the event that an LSE moves from a higher tier into a lower tier, due to the expiration of penalty points, we adopt a formula to address this scenario. All year-ahead RA deficiencies will be charged at the Tier 1 price, and in the month-ahead RA filing process, the LSE will pay the difference between its month-ahead tier penalty and the Tier 1 penalty that was already paid on its year-ahead RA deficiency, plus the LSE's current tier price on any incremental month-ahead RA deficiency. Accordingly, the following formula is adopted:

$$\text{Year-Ahead penalty} = \text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier 1 Price}$$

$$\text{Month-Ahead penalty} = [(\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier Price}^{\text{Month-Ahead}}) - \text{Year-Ahead penalty}] + (\text{Deficiency}^{\text{Month-Ahead incremental}} \times \text{Tier Price}^{\text{Month-Ahead}})$$

These clarifications to the penalty point system shall be effective beginning for the July 2023 RA filing.

4.8.2. Publication of Deficiency Information

Currently, certain information about RA citations and penalties is made public by the Consumer Protection Enforcement Division (CPED) on the Commission's website. Energy Division states, however, that information

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regarding the type of citation, type of RA deficiency, month of deficiency, deficiency amount, amount of deficiency as a portion of the LSE's requirement, and any points accrued are not published.[121] Energy Division notes that the purpose of the RA penalty program and citations is to deter non-compliance but in recent years, there has been a large increase in non-compliant LSEs. Since 2009, Energy Division states that 143 RA citations have been issued and paid, and at least eight system RA citations have been issued in August or September 2022. Without information on the magnitude and type of RA deficiencies, Energy Division states that policymakers do not have sufficient information to understand and address RA program violations.

Energy Division recommends that for month-ahead deficiencies, the following should be made public: the type of citation, type of RA deficiency, month of deficiency, deficiency amount, amount of deficiency as a portion of the LSE's requirement, and any points accrued. For year-ahead deficiencies, the information would remain confidential until after the compliance month to avoid revealing market-sensitive information since the LSE still has a chance to cure the year-ahead deficiency before the month-ahead process. Energy Division also proposes that citations for other program violations, such as late load forecasts and late RA filings, should not be redacted.

Cal Advocates and Joint Environmental Parties support Energy Division's proposal.[122] Cal Advocates states that publicizing this information will increase public knowledge of LSEs' ability to meet RA requirements, provide insights into reliability risks caused by LSEs' deficiencies, help stakeholders better understand

[121] Energy Division Phase 3 Proposals at 28.

[122] Cal Advocates Opening Comments at 14, Joint Environmental Parties Opening Comments at 6.

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problematic processes and timelines, and deter future deficiencies. Joint Environmental Parties remark that the RA program is currently inaccessible to the public as information is often scattered or withheld as confidential, making it difficult for the public to understand the impact of the RA program on contracting.

AReM and CalCCA oppose Energy Division's proposal.[123] AReM and CalCCA state that publishing the amount of an RA deficiency and the percent of an LSE's requirements can be used to back-calculate an LSE's RA requirements and determine the amount of load an LSE serves. CalCCA argues that even if posted after the compliance month, the information discloses an LSE's position as it continues to procure for future RA months. CalCCA cites the example that if information is posted the month after a July deficiency, the LSE may still be trying to procure for August and September to close the gap on those deficiencies. CalCCA argues that an LSE's net short RA position is protected under the Public Records Act and D.06-06-066, which protects IOU net short positions.

4.8.2.1. Discussion

The Commission concurs that more transparency into LSEs' compliance with the RA program is critical to providing insight into reliability risks related to LSEs' RA deficiencies and RA program violations. CalCCA likewise acknowledges the importance of additional transparency in the RA program, as it states that "[w]ithout additional transparency, understanding the causes of RA deficiencies will be unlikely and evaluating fixes to the problem haphazard."[124]

[123] AReM Opening Comments at 9, CalCCA Opening Comments at 16.

[124] CalCCA Opening Comments at 8.

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The Commission recognizes CalCCA's concern that disclosing an LSE's deficiency information following, for example, the July RA showing, may reveal the LSE's procurement status as the LSE continues to procure to close its deficiency gap for August and September. This could potentially put the LSE at a disadvantage with sellers as it continues to procure for the peak summer months. To address this concern, we find it reasonable that the proposed LSE deficiency information is published after the peak summer months (June-September), or no earlier than October 1 of the compliance year. The Commission also finds that disclosing the "amount of deficiency as a portion of the LSE's requirement" is not necessary information, in light of the other proposed disclosures. With these modifications, the Commission determines that Energy Division's proposal is a reasonable approach to increasing transparency regarding the RA program's compliance violations, and does not expose an LSE's net short position.[125] We adopt the proposal as modified here.

Accordingly, for any LSE's month-ahead and year-ahead deficiencies, the following information is not confidential and will be published on the Commission's website by CPED or Energy Division: the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued. The

[125] While we determine that the adopted disclosure is not confidential, we note that the Public Records Act, and related Commission decisions, allow the Commission to prevent the release of market-sensitive information that would harm energy markets and customers. D.06-06-066, Appendix A, § VI.A at 13. *See also* D.20-07-050 at OP 5 (adopting Appendix B, § II.B at 2 of D.08-04-023).

As provided by D.06-06-066, the Commission must weigh the need for open decision-making and meaningful public participation, with the legitimate needs of parties that appear before the Commission to determine whether data receives confidential treatment in a particular instance. Further, "[t]he merits of a claim that data are confidential will always depend on the context, and we must have the flexibility to make decisions based on specific facts rather than developing across-the-board rules." D.06-06-066 at COL 18, 22.

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information will be published no earlier than October 1 of the compliance year. For other non-deficiency RA program violations, such as late load forecasts and late RA filings, the information on the RA citation is deemed not confidential and may be published on the Commission's website by CPED or Energy Division.

4.8.3. Untimely Local Waiver Advice Letters

Local RA waiver requests must be submitted via a Tier 2 Advice Letter, as provided in D.19-06-026. Pursuant to the 2023 Resource Adequacy Guide, local waiver Advice Letters are due at the same time as the year-ahead and month-ahead RA filings. Energy Division points out that several LSEs are repeatedly late in filing local waiver Advice Letters and there is no associated penalty with late filings.[126] Energy Division proposes that late local waiver Advice Letters should not be accepted and should be denied.

No parties commented on this proposal. The Commission agrees with Energy Division that late local waiver submissions should not be accepted past the stated deadline and should be automatically denied. Accordingly, a local RA waiver request that is filed past the submission deadline will be rejected.

4.8.4. CAM/RMR Credit Allocations

CAM and Reliability Must Run (RMR) credits are allocated to LSEs on a quarterly basis pursuant to D.14-06-050 and allocations are due 45 days before the RA filing deadline. Energy Division states that RMR allocations are dependent on CAISO providing the total Commission-jurisdictional share of RMR credits, which are generally not provided until October.[127] Energy Division notes that for the 1st Quarter of 2023, CAM and RMR credits were due on October 3, 2022, 45 days before the January 2023 filings, which were due on

[126] Energy Division Phase 3 Proposals at 27.

[127] Energy Division Phase 3 Proposals at 27.

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November 17, 2022. However, CAISO did not provide the Commission's RMR share by that date. Therefore, Energy Division proposes that for the 1st Quarter of each year, Energy Division will provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the RMR credits to Energy Division.

CAISO supports this proposal and echoes that it cannot provide Energy Division with RMR credits until October of each year.[128]

The Commission agrees that the proposed timing is reasonable and would give Energy Division time to allocate CAM and RMR credits based on the total Commission-jurisdictional share of RMR credits. Accordingly, for the 1st Quarter of every year, Energy Division will provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the CPUC-jurisdictional RMR credits to Energy Division.

4.9. Annual Load Forecasts for RA Requirements

In the current RA program, LSEs submit binding load forecasts for the Commission to determine an LSE's year-ahead requirements and LSEs may update their monthly load forecasts to account for load migration that may occur throughout the year. Energy Division states that the monthly load forecast updates add administrative complexity to the RA program because the monthly updates modify the monthly RA requirements, require significant Commission Staff resources, and call into question the purpose of the binding load forecast.[129] Energy Division adds that allowing monthly updates also provides an opportunity for load migration to insert reliability risk.

[128] CAISO Opening Comments at 10.

[129] Energy Division Phase 3 Proposals at 35.

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Energy Division seeks consideration for locking in year-ahead system and local forecasts for the RA program, obviating the need for monthly load forecast updates. Under this proposal, system and local RA requirements would vary by month but be locked in for the entire year, which would give LSEs and the Commission more certainty regarding which entity is responsible for the RA obligation.

MRP, PG&E and Vistra support this proposal.[130] PG&E asserts that the monthly process is burdensome and complex, and results in only minor changes to the RA requirements. PG&E points out that larger load migration changes are already accounted for and are not a serious concern during the monthly true-up process because CCAs are required to provide at least 12 months' notice before implementation or expansion into new territory. MRP opposes the current monthly framework of the RA program in favor of an annual framework.

AReM, CalCCA, and Shell oppose the proposal.[131] AReM objects to locking in annual load so long as customers have a choice to move between IOUs and CCAs. Shell comments that it is important to calculate monthly obligations based on the most current load forecasts; otherwise, LSEs that lose load incur obligations for load that is the responsibility of another LSE. CalCCA states that the proposal will lead to inaccuracies in requirement allocation as load moves among LSEs but requirements stay the same. SDG&E asserts that additional

[130] MRP Opening Comments at 26, PG&E Reply Comments at 9, Vistra Opening Comments at 23.

[131] AReM Opening Comments at 12, Shell Opening Comments at 7, CalCCA Opening Comments at 34.

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analysis is needed to determine whether the year-ahead forecast can be reliable enough to estimate demand to meet the 1-in-2 standard.[132]

The Commission agrees that the monthly load forecast update process requires significant Commission Staff resources, while generally resulting in only small modifications to the RA requirements. As pointed out by PG&E, any larger changes in load migration will already be accounted for because CCAs are required to provide at least a one-year notice prior to implementation or expansion. With the existing monthly true-up process, month-to-month requirements do not change significantly as a result of the monthly load forecast updates. In considering comments on the proposed decision, the Commission finds it reasonable to allow one mid-year load migration update in mid-February to cover May-December load migration, similar to the local and flexible RA true-up process. Other than the one load migration update, the Commission finds it reasonable that an LSE's load forecasts should be locked in for January-April and May-December.

In adopting this requirement, the incremental local and flexible RA true-up will be retained; however, the forecast submittal used in the true-up will be due in February rather than mid-March. The quarterly CAM/RMR process will be modified to only provide LSEs refreshed CAM/RMR credits for June-December based on CAM resource information and the updated June-December forecasts. Revised load forecasts will be due mid-February with an LSE's April month-ahead RA filing. These forecasts will be reviewed for plausibility before being used to allocate local and flexible RA true-ups and CAM/RMR credits. The May-December revised forecast will be used in determining an LSE's month-

[132] SDG&E Opening Comments at 8.

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ahead system obligations for May-December. Energy Division Staff is authorized to review the administrative impact of this requirement in 2024 and submit a proposal with modifications into the RA proceeding if warranted. Accordingly, an LSE is permitted one load migration update in mid-February to cover May to December load migration; otherwise, an LSE's load forecast is locked in for the January-April timeframe and May-December timeframe.

5. Demand Response Issues

5.1. Qualifying Capacity of Supply-Side DR Resources and CEC Working Group on Supply-Side DR

In the RA program, RA capacity from DR resources administered by the IOUs is allocated to LSEs as DR credits that are counted towards an LSE's RA requirements.[133] Currently, the QC value of DR resources for both IOUs and third-party Demand Response Providers (DRPs), with the exception of resources participating in the Demand Response Auction Mechanism (DRAM) pilot, is based on the Load Impact Protocols (LIPs), which are informed and adjusted by historic DR performance. In D.21-06-029, the Commission discussed CAISO's initiation of proposed revision request (PRR) 1280 to its Business Practice Manual. The Commission identified that the revision would reject any non-net neutral credits that lower an RA requirement without the resource being shown on the CAISO Supply Plan and determined its implementation would effectively mean that DR credits allocated to LSEs by the Commission would no longer be accepted by the CAISO.[134] CAISO initially proposed an Effective Load Carrying

[133] *See generally* D.09-06-028.

[134] D.21-06-029 at 27. CAISO subsequently withdrew PRR 1280 on August 30, 2021. *See* http://www.caiso.com/Documents/ProposedRevisionRequest1280WithdrawalCall091321.html.

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Capability (ELCC) methodology to determine the QC of variable-output DR, rather than the LIPs, as CAISO stated that LIPs do not consider use limitations and portfolio interactions, and thus overvalue DR resources' contributions to reliability.

In D.21-06-029, the Commission declined to adopt an ELCC methodology for DR counting and instead adopted a working group process led by the CEC to develop a DR QC counting methodology and develop recommendations for a comprehensive and consistent measurement and verification strategy, including a new counting methodology for DR addressing *ex post* and *ex ante* load impacts for implementation as early as practicable. The CEC was requested to submit recommendations for implementation for the 2023 RA year.

The CEC submitted a Qualifying Capacity of Supply-Side Demand Response Working Group Report (Initial CEC Report) on February 18, 2022, in which it noted that there was insufficient time to develop a permanent QC methodology for the 2023 RA year and that stakeholders asserted the Working Group should await the outcome of the Reform Track process before making a recommendation.[135]

In D.22-06-050, the Commission found insufficient record to adopt a DR QC counting proposal for the 2023 RA year.[136] The Commission determined that the CEC Working Group should continue to develop long-term recommendations, consistent with the adopted Reform Track framework, and those recommendations should focus on the 2025 RA year and beyond.[137] The

[135] Initial CEC Report at 34.

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

[137] *Id*. at COL 8.

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Commission specifically requested that the CEC Working Group develop recommendations that consider the following issues for the 2025 RA year:[138]

(1) Whether the proposals that are presented in the CEC's stakeholder process are reasonable and appropriate to determine the QC of DR resources;

(2) Whether the DR QC methodology reflects the contributions of DR resources to reliability;

(3) Whether the DR QC methodology is compatible with the new RA framework for the 2025 RA year and beyond;

(4) Whether the DR QC methodology is transparent and how it could be implemented in a time-efficient manner;

(5) Whether and to what extent alignment of DR M&V methods in the operational space for CAISO market settlement purposes with methods to determine DR QC in the planning space should be achieved, and if so, how;

(6) Whether, and if so what, enhancements to intra-cycle adjustments to DR QC during the RA compliance year, as adopted in D.20-06-031, are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space; and

(7) Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology.

The CEC recommenced the Working Group pursuant to D.22-06-050 with a deadline of February 1, 2023 to submit final recommendations.

5.1.1. CEC Working Group Report

On January 25, 2023, the CEC adopted the report that resulted from the CEC Supply-Side DR QC Working Group - *The Qualifying Capacity of Supply-Side Demand Response Working Group Final Report* (CEC Report). The CEC Report provides the CEC's final findings and recommendations from the Working

[138] *Id.* at OP 11.

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Group. On February 2, 2023, an ALJ ruling was issued that attached the CEC Report. On February 15, 2023, an ALJ ruling provided questions and established a comment schedule on the CEC Report. On February 24, 2023, an ALJ ruling issued a corrected final version of the CEC Report.

The CEC Report makes 18 recommendations:[139] (1) apply a consistent QC framework and methodology across DR resources; (2) adopt an incentive-based approach; (3) adopt the capacity shortfall penalty incentive mechanism with forced outage adder; (4) adopt the *ex ante* capability profile and *ex post* regression approach; (5) require resources to show takeback; (6) require DR providers to submit capability profiles and slice-of-day table to summarize QC values; (7) reduce reporting requirements for QC determination; (8) plan to produce final QC numbers by June 1 preceding the RA compliance year; (9) adopt streamlined QC approval criteria; (10) the Commission should implement the proposed penalty mechanism and CAISO should exempt DR from the RAAIM; (11) phase in incentive-based approach over time; (12) require DR providers to use the same baseline for settlement and ex post evaluation unless an alternative is more accurate but unable to be used for settlement; (13) adopt bid normalization for load impacts in ex post capacity valuation; (14) reduce the threshold required for midyear QC update; (15) eliminate the components of the PRM adder associated with operating reserves and load forecast error; (16) convert the forced outage adder to a multiplier applied in the capacity shortfall penalty; (17) maintain the distribution loss factor adder in QC values; and (18) update transmission loss factors and include the adder as a credit.

[139] CEC Report at 47-50.

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During the CEC Working Group process, stakeholder proposals were provided by CLECA, DSA in coordination with SDG&E, OhmConnect, CEDMC and CEC Staff. The CEC Report ultimately recommends adopting the CEC Staff proposal as part of its recommendations. The five Working Group proposals are summarized below.

5.1.2. CLECA Proposal

CLECA proposes adapting the status quo LIP-based methodology to the SOD framework.[140] CLECA notes that the LIPs already produce hourly expected load reductions that are averaged under the current process, and that under the SOD framework, they simply do not need to be averaged. CLECA proposes that DR providers should be required to account for any significant spillover effects that increase or decrease load before or after the event. The CEC notes that CLECA's emphasis in its proposal is more on flexibility in when DR providers can provide capacity and requirements for counting capacity across hours rather than on the specific method used to calculate the values.[141]

5.1.3. DSA Proposal

The DSA proposal is an application of the LIPs to the new SOD framework.[142] DSA's proposed modifications include updating planning temperatures to the "worst day" as defined in the RA program, allowing DR resources the flexibility to provide capacity value based on need, and accounting for spillover in nonevent hours. Much of the DSA proposal focuses on standardization of reporting requirements and outputs, including a SOD table to show the hourly load impacts for the worst day in each month and a

[140] CEC Report at 8.

[141] *Id.*

[142] *Id.* at 11.

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time-temperature matrix for weather-sensitive resources. DSA also proposes that a central planning authority produce a "reliability risk heatmap" for each compliance year that will help DR providers align resources and programs with system need. DSA also includes two *ex post* performance metrics in this proposal: (1) the bid alignment metric measures the extent to which resources bid as expected based on the associated SOD table or time-temperature matrix or both; and (2) the performance alignment metric measures the extent to which resources perform as expected when dispatched.

5.1.4. OhmConnect Proposal

OhmConnect proposes using the same underlying methods used in the current LIP-based status quo, and focuses its proposal on removing, or otherwise streamlining, the LIP reporting requirements not directly applicable to QC.[143] Reporting changes proposed by OhmConnect include streamlining evaluation plan requirements, eliminating *ex post* and *ex ante* impact estimates not relevant to QC valuation, eliminating all non-event-based DR protocols, and streamlining evaluation reports.

5.1.5. CEDMC Proposal

CEDMC proposes an *ex post* incentive structure that levies a penalty on underperformance to ensure delivered capacity.[144] This proposal is aimed at reducing the burden and risk for DR providers and Energy Division Staff because DR providers bear compliance costs of participation and uncertainty of awarded QC, and Energy Division Staff are responsible for auditing submissions and approving final awarded QC. The central aspect of the CEDMC proposal is

[143] *Id.* at 12.

[144] *Id.* at 13.

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a penalty adapted from PG&E's Capacity Bidding Program that would be applied to the resource's performance during the best hour of each month.

5.1.6. CEC Staff Proposal

CEC Staff recommends the Commission move away from the LIPs approach and adopt an incentive-based QC approach. CEC Staff states that replacing the upfront forecasting approach with an incentive-based framework can prompt DR providers to commit to achievable capacity contributions and to meet those commitments while streamlining the process for both DR providers and Commission Staff.[145] CEC Staff proposes that the QC value would be based on the *ex ante* hourly capability profile created by the DR provider and that a capacity shortfall penalty with a forced outage multiplier would be applied to the *ex post* demonstrated capacity if it falls short of the committed capacity.[146] The demonstrated capacity would be based on CEC Staff's proposed bid-normalized load impact metric, which normalizes load impacts to the amount bid for events when delivered energy may be lower than *ex ante* because of partial dispatches rather than due to underperformance. Both QC and demonstrated capacity values would account for weather sensitivity by using linear regression to find the intersection of the hourly capability profile and the bid-normalized load impacts with the planning temperature.

5.1.7. Comments on Proposals and CEC Working Group Report

Parties take different positions on the various supply-side DR QC proposals, with no proposal receiving consensus support. Some parties express dissatisfaction with the Working Group process overall and the report's

[145] *Id.* at 1.

[146] *Id.* at 14.

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representation of various party perspectives,[147] while others counter that the process was fair and accurately represents positions.[148]

While CAISO, CEDMC/CPower, and OhmConnect support further consideration of the CEC's proposal, [149] many parties (including CAISO, CEDMC/CPower, and OhmConnect) identify that the proposed penalty mechanism requires further refinement to clarify how it would be implemented[150] and that the proposal should be vetted using historical data.[151] Cal Advocates, CLECA, DSA, PG&E, SCE, and SDG&E oppose adopting the CEC's proposal. CLECA believes much greater evidence is needed to ensure it is workable and does not see benefit in continued work on the proposal.[152] DSA is concerned that because the proposal is a significant departure from the historically used approach, the proposal should be tested against other incentive-based methodologies.[153] DSA also believes the enforcement mechanism needs additional clarity.[154] SCE thinks a proof-of-concept exercise is needed on the

[147] CLECA Opening Comments on CEC Report at 2, SDG&E Opening Comments on CEC Report at 3, DSA Opening Comments on CEC Report at 6.

[148] CEDMC/CPower Reply Comments on CEC Report at 2-3, OhmConnect Reply Comments at 2-3.

[149] CAISO Opening Comments on CEC Report at 4, CEDMC/CPower Opening Comments on CEC Report at 10, OhmConnect Opening Comments on CEC Report at 10.

[150] OhmConnect Opening Comments on CEC Report at 4, CEDMC/CPower Opening Comments on CEC Report at 1, DSA Opening Comments on CEC Report at 5, SCE Reply Comments on CEC Report at 2.

[151] CAISO Opening Comments on CEC Report at 6, CLECA Opening Comments on CEC Report at 9, DSA Opening Comments on CEC Report at 4, PG&E Opening Comments on CEC Report at A-5, SCE Opening Comments on CEC Report at 3, SDG&E Opening Comments on CEC Report at Attachment A.

[152] CLECA Opening Comments on CEC Report at 10.

[153] DSA Opening Comments on CEC Report at 4-5.

[154] *Id.*

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CEC's *ex post* methodology before the Commission adopts it.[155] SDG&E believes the prescriptive approach of the proposal needs to be tested in the field before it is adopted.[156]

PG&E, SCE and SDG&E support DSA's proposal.[157] CLECA asserts its own proposal should be adopted but supports DSA's proposal as an alternative.[158] OhmConnect believes DSA's proposal is too complex and supports CLECA's proposal with simplified LIPs if LIPs are retained as the basis for QC.[159] SDG&E sees merit in some of CLECA's proposal but opposes retaining the PRM adder and removing availability requirements between 4 p.m. and 9 p.m.[160] CEDMC/CPower oppose both DSA's and CLECA's proposals as they believe none of the LIP-based proposals address issues DRPs face under the LIPs.[161]

CEDMC/CPower offer that if the Commission retains LIPs in some form, it should adopt OhmConnect's simplified LIPs proposal.[162] Cal Advocates believes most changes OhmConnect proposes making to the LIPs are unnecessary and the current LIP guidelines are sufficient.[163] SDG&E supports

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[155] SCE Opening Comments on CEC Report at 8.

[156] SDG&E Opening Comments on CEC Report at Attachment A.

[157] PG&E Opening Comments on CEC Report at 2, SCE Opening Comments on CEC Report at 2, SDG&E Opening Comments on CEC Report at Attachment A.

[158] CLECA Opening Comments on CEC Report at 2.

[159] OhmConnect Opening Comments on CEC Report at 9.

[160] SDG&E Opening Comments on CEC Report at Attachment A.

[161] CEDMC/CPower Opening Comments on CEC Report at 2-3.

[162] *Id*. at 3.

[163] Cal Advocates Opening Comments on CEC Report at 7.

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only some of the proposed changes to the LIPs.[164] CLECA believes OhmConnect's proposal requires further refinement.[165]

OhmConnect, Cal Advocates, and SDG&E oppose CEDMC's proposal. OhmConnect believes CEDMC's proposal would be vulnerable to the same criticisms as DRAM.[166] Cal Advocates asserts it would create a disconnect between claimed QC value and actual resource performance.[167] SDG&E finds various shortcomings with the proposal, including reliance on settlement baselines, not addressing weather sensitivity of DR, and penalty design that needs further vetting.[168]

Parties also made comments on the CEC Working Group Report recommendations that were not related to any proposed QC methodology. The issue of adders is discussed in a later section of this decision that discusses Energy Division's proposal on TLF and PRM adders.

5.1.8. Discussion

The Commission appreciates the ongoing efforts by CEC Staff and parties in leading, and participating in, the supply-side DR QC Working Group over the last two years. Significant work has gone into this process and meaningful progress has been made. While we have seen advancement in the thinking on what the structure of a future supply-side DR QC approach could be, party comments demonstrate a plurality of views that no single proposal is sufficiently developed or tested to warrant adoption at this time. While we acknowledge the

[164] SDG&E Opening Comments on CEC Report at Attachment A.

[165] CLECA Opening Comments on CEC Report at 10.

[166] OhmConnect Opening Comments on CEC Report at 9-10.

[167] Cal Advocates Opening Comments on CEC Report at 4.

[168] SDG&E Opening Comments on CEC Report at Attachment A.

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existing LIPs process is imperfect, we find that maintaining the current method is preferable to transitioning too quickly to an untested method, which could have unanticipated outcomes.

Although we decline to adopt any new approach at this time, we agree with parties that see promise in the CEC's proposal, if provided with additional time for refinement and testing. We therefore maintain the LIPs as the supply-side DR QC methodology at this time and authorize Energy Division to lead a Working Group, with support from CEC Staff, and submit a joint proposal in the RA proceeding for an incentive-based supply-side DR QC methodology in December 2024. The Energy Division-led Working Group should focus its efforts on refining certain elements of the CEC's methodology that were identified by parties in comments. Those elements include, but are not limited to, the formula for the bid-normalized load impact metric, the design of the capacity shortfall penalty, and the enforcement mechanism for the capacity shortfall penalty.

The schedule for the Working Group and the joint report is adopted as follows:

Milestone	**Timeframe**
Initiate Working Group to refine specific elements of the CEC proposal, as directed by Commission Decision.	July 2023
LIP process begins for 2025 RA compliance year. In *ex post* analysis on 2023 performance, the CEC methodology is run side-by-side by LIPs on a "what if" basis with no penalties applied.	December 2023
Final LIP reports for 2025 RA compliance year filed. Energy Division and CEC draft joint report summarizing *ex post* results for 2023.	April 2024
Energy Division and CEC continue refining incentive-based proposal, incorporating learnings from "what if" exercise.	April - December 2024

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Energy Division and CEC submit refined incentive-based proposal to the RA proceeding.	December 2024
LIP process begins for 2026 RA compliance year.	December 2024

While this Working Group process is ongoing, we also authorize Energy Division to pursue simplification of the current LIP requirements using a stakeholder process to develop a proposal for Commission consideration. We authorize Energy Division Staff to establish a schedule for the process and the proposals.

5.2. Proxy Demand Response (PDR) Bid Cap

Energy Division has concerns that the bidding practices of many PDRs lead to suboptimal outcomes for ratepayers.[169] Energy Division is specifically concerned that many PDRs bid strategically to reduce their likelihood of being selected in the CAISO market, even on days when grid emergencies are anticipated based on the demand forecast. Compounding this issue is the fact that wholesale prices in the CAISO market, particularly in the day-ahead market, are not always reliable indicators of a grid emergency. Energy Division describes that in both the 2020 and 2022 heatwaves, CAISO declared an Energy Emergency Alert (EEA) Watch for hours that cleared at less than $1,000/MWh in the day-ahead market and/or the real-time market. Energy Division notes that CAISO inserts bids for Reliability Demand Response Resources (RDRR) at $950/MWh and will accept them if there are insufficient resources at a lower price.

As a result, there may be times when RDRR is dispatched, while "economic" PDRs that bid at the market cap would not be dispatched by CAISO,

[169] Energy Division Phase 3 Proposals at 9-10.

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particularly long-start PDRs that can only bid into the day-ahead market. Energy Division identifies that this scenario effectively creates an irrational dispatch order wherein RDRR gets triggered while other "economic" DR resources, which are receiving ratepayer-funded RA compensation, become stranded assets during a grid emergency.

To remedy this issue with irrational dispatch, Energy Division proposes establishing a bid cap for RA-eligible PDRs bidding into the CAISO market that is below the price trigger for RDRR. Specifically, Energy Division proposes that the value of the PDR-specific bid price cap be no higher than $500/MWh for both the day-ahead and real-time markets. Energy Division believes this cap is appropriate because DMM found that prices rarely exceeded $500/MWh (<1 percent of intervals) from July 2021 to August 2022, and the day-ahead market price exceeded $500/MWh in about 3 percent of intervals in September 2022,[170] which is on par with the minimum monthly availability requirement currently in place for RA-eligible DR of 24 hours per month.

To assess compliance, Energy Division proposes to review the applicable tariffs or LSE contracts to determine that they include a bid cap provision. If tariffs or contracts require resources to bid below the PDR bid cap, LSEs will be considered provisionally compliant in meeting their RA requirements. Once the data becomes available "*ex post*," Energy Division would review the bid data set to assess whether any PDRs were in violation of the cap. If Energy Division identifies a PDR in violation of the cap, the resource would be treated as if it were not made available to the CAISO on a Supply Plan. As with other RA resources, a deficiency notice would be issued, depending on if the LSE

[170] Q3 2022 Report on Market Issues and Performance, CAISO Department of Market Monitoring, December 14, 2022, at 9.

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otherwise had enough capacity to meet its RA requirement without violating PDR(s).

5.2.1. Comments on Proposal

PG&E supports Energy Division's proposal and believes a bid cap would support greater dispatch of PDRs, but requests the Commission not issue deficiency notices to the IOUs for non-compliance by third-party DRPs because the IOUs have no control over how DRPs bid DRAM resources or other third-party DR contract resources into the market.[171] SCE also opposes penalizing the IOUs for non-compliance by a third-party and proposes that if a penalty is imposed, the IOUs should be able to establish contract provisions that withhold a percentage of a third-party DRP's capacity payment or impose a deposit requirement that could be forfeited after review of the bid data rather than retroactively discrediting an LSE's supply plan.[172]

Joint DR Parties, CESA and Vistra oppose a bid cap amount of $500/MWh.[173] Joint DR Parties assert that more recent CAISO reports from Summer 2022 demonstrate a bid cap is not needed to ensure PDRs are being scheduled in the CAISO market and believe that the cap would put third-party DR at a competitive disadvantage with IOU DR programs, like PG&E's Capacity Bidding Program, which has a $650/MWh bid cap.[174] Joint DR Parties also argue that the bid cap does not account for spikes in natural gas prices, such as those

[171] PG&E Opening Comments at 14.

[172] SCE Opening Comments at 11.

[173] Joint DR Parties Opening Comments at 4, CESA Opening Comments at 10, Vistra Opening Comments at 27.

[174] Joint DR Parties Opening Comments at 4-6.

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that pushed the clearing price beyond $500/MWh in December 2022.[175] CESA asserts that a bid cap at $500/MWh would not account for DR resources that may be located in load pockets where locational marginal prices tend to be higher or that have a higher marginal cost of dispatching.[176] Vistra argues a $500/MWh bid cap would create a disincentive for participation and would artificially suppress energy prices and shift these costs to the RA market.[177]

DMM overall agrees that RDRR should not be dispatched before or ahead of PDRs.[178] It identifies that in practice, conditions for PDRs to exceed RDRR bids in the real-time market have been very limited and cautions against setting a bid cap that is too low, because (1) the marginal cost of these resources is unclear, and (2) it may result in dispatches during milder conditions that result in the resources not being available when market conditions are tighter.[179] DMM therefore proposes that a $949/MWh bid cap for PDRs be established to address the concern.[180] Although CESA and OhmConnect do not support a bid cap, if the Commission were to establish one, they would also support a $949/MWh bid cap.[181]

CLECA and Vistra agree that RDRR should not be dispatched ahead of or instead of PDRs and that offers should be at a price that results in a more rational

[175] *Id.* at 6.

[176] CESA Opening Comments at 10.

[177] Vistra Opening Comments at 27.

[178] DMM Opening Comments at 3, CLECA Reply Comments at 6.

[179] DMM Opening Comments at 5.

[180] *Id.*

[181] CESA Opening Comments at 10, OhmConnect Reply Comments at 3.

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dispatch order.[182] Vistra proposes that instead of Energy Division's proposed $500/MWh bid cap, the Commission implement a merit order proposal wherein RDRR offers, when released through the CAISO market operations action, are released into the supply stack at 110 percent of the CAISO's Soft Energy Bid Cap or Hard Energy Bid Cap, not to exceed $2,000/MWh, and that PDR offers be limited to no more than $100/MWh less than RDRR.[183] OhmConnect supports Vistra's proposal.[184]

5.2.2. Discussion

We agree with Energy Division and PG&E that implementing a bid cap for PDRs would prevent the possibility of an irrational dispatch order where RDRR is dispatched before PDRs. We also agree that this would support greater dispatch of PDRs, which would increase their contributions to reliability. We do, however, recognize that other parties such as DMM are concerned that increasing the frequency of dispatch could decrease the availability of PDRs during the most stressed grid conditions when they are needed most, which could impact reliability. While many parties agree that RDRR should not be dispatched before PDRs, parties are mixed on what the appropriate level for the PDR bid cap should be.

We find it appropriate to adopt a PDR bid cap of $949/MWh. While both the proposed $500/MWh and $949/MWh would result in a more appropriate dispatch order, we find that a $949/MWh cap, which most closely tracks to the RDRR trigger, to be most strongly supported for delivering the intended dispatch order without potential unintended consequences. We clarify that this

[182] CLECA Reply Comments at 6, Vistra Opening Comments at 27.

[183] Vistra Opening Comments at 28-29.

[184] OhmConnect Reply Comments at 4.

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cap will apply to the total cost of all bid components, including start-up costs and minimum load costs. This definition is consistent with the circumstance contemplated by and purpose of the cap – to prevent the possibility of an irrational dispatch order and to increase the contribution of PDRs to reliability. We emphasize that the PDR bid cap is a cap and not a floor, and that supply-side DR resources are expected to competitively bid into the CAISO wholesale market, consistent with CAISO market rules and the Commission's DR principles adopted in D.16-09-056. We do, however, intend to revisit this requirement as needed and as more information is gathered on PDR bidding behavior and dispatch.

We therefore require that PDR bids may not exceed $949/MWh in either the day-ahead or real-time markets in order for those resources to be counted towards RA requirements. This requirement will help ensure that all available PDR resources are exhausted in the real-time market prior to enabling RDRR under EEA notice conditions. This requirement will take effect for the 2024 RA compliance year and will apply to all PDRs procured for RA and in all months, with the exception of DRAM resources contracted for the 2024 RA delivery year. If DRAM is extended beyond the 2024 delivery year, then the PDR bid cap will apply to DRAM resources in future years.

We reiterate that the PDR bid cap adopted here is imposed on LSEs strictly as an RA requirement, consistent with the Commission's authority and obligations under Public Utilities Code Section 380. Section 380(h) provides the Commission discretion to determine how to implement its RA program.[185] In particular, Section 380(h)(6) requires the Commission to determine and authorize

[185] "[W]hile [Section 380] sets out requirements for an RA program, subdivision (h) gives us discretion to determine the best way to implement those requirements." D.06-04-040 at 8-9.

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the most efficient and equitable means to ensure "that investments are made and in new and existing demand response resources that are cost effective and help to achieve electrical grid reliability and the state's goals for reducing emissions of greenhouse gases." The proposed PDR bid cap is a limiter on RA eligibility and not on wholesale market participation generally. As noted in D.20-06-028, California's RA market is voluntary and nothing precludes suppliers from bidding, unconstrained, into the CAISO's day-ahead and real-time markets without any RA obligations.[186]

We also adopt Energy Division's proposal to verify compliance with the bid price cap by reviewing bid price requirements in DR tariffs/contracts "ex ante" and by reviewing bid data "ex post" to verify that the bid price cap was not exceeded. We authorize the Energy Division Director or their delegated Staff to issue correction or deficiency notices to LSEs if any PDRs shown on their Supply Plans are found non-compliant and the LSEs otherwise would not have had enough capacity to meet their RA requirements without the non-compliant PDRs.

We acknowledge SCE's concern that LSEs do not have control over how a third-party DRP bids its resources into the CAISO market. We recognize that LSEs may wish to revise their tariffs and contracts to require third-party DRPs to comply with the bid price cap or add contract provisions that allow LSEs to withhold payment until compliance with the bid price cap is verified or to pass through any RA penalties incurred due to uncured deficiencies and nothing in this decision would prohibit LSEs from doing so.

[186] D.20-06-028 at 36.

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We also address the distinction Joint DR Parties made between Energy Division's proposed PDR bid cap and the existing $650/MWh bid cap for PG&E's Capacity Bidding Program (CBP), and we clarify that the PDR bid cap will apply to all PDRs procured for RA, including PDRs participating in CBP. In addition, in response to parties' comments that long-start PDRs cannot be bid into the real-time market, we clarify that the bid cap adopted here does not require such resources to bid into the real-time market for hours they are not already dispatched.

5.3. Expanding Prohibited Resources Policy

The Commission established the Prohibited Resources policy in D.16-09-056, which prohibited the use of distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas (Prohibited Resources) to achieve incremental load reduction in non-exempt DR programs during DR events. This prohibition applied to all DR providers, including third party DRPs. D.16-09-056 also required IOUs to require attestations for new non-residential customers and design an audit verification plan.[187]

Energy Division identifies that in recent years DR resources have been used by non-IOU LSEs to meet their RA obligations, in line with loading order.[188] Energy Division states that because the Commission's existing Prohibited Resources policy, established in D.16-09-056 and modified by D.18-06-012, was adopted for IOU-procured DR, there is a risk that customers who participate in DR procured by non-IOU LSEs could participate using prohibited resources to

[187] D.16-09-056 at OPs 3-5.

[188] Energy Division Phase 3 Proposals at 12.

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serve load during a DR event. Energy Division asserts that such an outcome would undermine the Commission's goal for RA-eligible DR resources to be clean. Energy Division also identifies that the existing policy creates a competitive disadvantage for customers participating in IOU-managed DR programs.

Energy Division therefore proposes: (1) requiring all RA-eligible DR resources to abide by the Prohibited Resources policy as defined in D.16-09-056 and subsequent decisions and resolutions, (2) extending the Prohibited Resources Verification Plan to all RA-eligible DR resources, and (3) recovering associated costs through the existing mechanism or through another mechanism if adopted through the five-year DR programs and budget applications.

5.3.1. Comments on Proposals

Joint Environmental Parties, SDG&E, and Cal Advocates support the proposal.[189] Joint Environmental Parties assert the Prohibited Resources policy should be applied to all RA-eligible DR resources, so that non-IOUs do not interpret the existing policy as a loophole.[190] Joint Environmental Parties also state that D.16-09-056 found that Pub. Util. Code Section 380.5 makes clear that efforts to incorporate DR into the RA program should also reduce GHG emissions.[191] SDG&E asserts that Commission adoption of this requirement will place IOU DR on equal footing with third-party DR and will further the Commission's goals of reducing GHG emissions.[192] Cal Advocates argues that

[189] Joint Environmental Parties Opening Comments at 5, SDG&E Opening Comments at 5, Cal Advocates Opening Comments at 15.

[190] Joint Environmental Parties Opening Comments at 6.

[191] *Id*. (referencing D.16-09-056 at 92).

[192] SDG&E Opening Comments at 5.

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the enforceable prohibition of fossil fueled generation from DR is required to enforce California's clean energy policies.[193]

SCE agrees that the Prohibited Resources policy should apply to all RA-eligible DR resources, but believes this issue would be more appropriately handled in the DR proceeding.[194] Enchanted Rock supports the proposal but requests that the requirements should be augmented to allow RPS-eligible fuels' participation in DR programs to allow microgrids to participate.[195] Mainspring requests the Commission take an approach that allows resources that are capable of fuel switching between non-renewable and renewable fuels to be allowed to participate in DR programs.[196]

5.3.2. Discussion

We agree with Energy Division and parties that extending the Prohibited Resources policy to all RA-eligible DR resources is in line with the Commission's initiating objectives in adopting the original Prohibited Resources policy in D.16-09-056 and aligns with state policy that DR resources participating in RA programs should be clean. With regard to the proposals from Enchanted Rock and Mainspring to expand the renewable fuel eligibility definition, we find this question out of scope for this proceeding.

We therefore adopt Energy Division's proposal and require, beginning with the 2024 RA compliance year, that (1) all RA-eligible DR resources must abide by the Prohibited Resources policy as defined in D.16-09-056 and subsequent decisions and resolutions, (2) the Prohibited Resources Verification

[193] Cal Advocates Opening Comments at 15.

[194] SCE Opening Comments at 12.

[195] Enchanted Rock Reply Comments at 4.

[196] Mainspring Reply Comments at 2.

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Plan applies to all RA-eligible DR resources, and (3) associated costs of implementation shall be recovered through the existing mechanism or through another mechanism if adopted through the current or subsequent five-year DR programs and budget applications.

5.4. Dispatch Requirements for Emergency DR Resources Qualifying for RA

Prior Commission decisions transitioned RDRR into a price-responsive product in order to make it more useful and to make it available for dispatch prior to CAISO procuring emergency supplies from neighboring balancing authorities or exceptionally dispatching resources.[197]

Energy Division expresses concern that the current RDRR dispatch approach results in RDRR being underutilized.[198] Energy Division explains that under CAISO's interpretation of NERC protocols, RDRR is prevented from being dispatched during or before an EEA 1 and if these resources are dispatched, CAISO automatically escalates to an EEA 2. In addition, market prices tend to increase substantially when the marginal clearing price is set by RDRR bids.

Energy Division asserts that this dispatch approach effectively means that RDRR is not providing RA because the resources are not used for mitigation or avoidance of emergencies, but only mid-emergency management. Moreover, while CAISO can declare an EEA Watch in the day-ahead or day-of timeframe when CAISO forecasts "one or more hours may be energy deficient,"[199] an EEA 2 must be declared in real-time when all available resources are in use and CAISO

[197] *See* CPUC Reliability-Based Demand Response Settlement, R.07-01-041, Phase 3 at 4-5 (adopted in D.10-06-034); D.18-11-029 at 23.

[198] Energy Division Phase 3 Proposals at 17.

[199] CAISO Operating Procedure 4420 at 7.

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is no longer able to meet expected energy requirements.[200] As a result, Energy Division notes that these resources are infrequently dispatched. Therefore, rather than displacing procurement and preventing scarcity conditions, the current set of dispatch practices for RDRR contributes to the conditions it is meant to avoid – emergency procurement from neighboring balancing authorities and scarcity pricing.

Energy Division asserts that, in effect, ratepayers are paying twice, because RDRR receives RA capacity payments but does not appear to be meeting its intended objective of displacing procurement, addressing or mitigating scarcity pricing, or avoiding reliability event emergency conditions.

To address this, Energy Division proposes that RDRR (including the Base Interruptible Program (BIP)) may not count towards RA requirements unless it is available to be dispatched before an EEA 2. Specifically, Energy Division proposes that either: (1) RDRR not count towards RA requirements under the current paradigm in which these programs are only dispatched by CAISO at an EEA 2, or (2) RDRR count toward RA requirements, but only if the IOUs are able to dispatch RDRR at a day-of EEA Watch, or before or during an EEA 1. Energy Division further proposes that the IOUs be given discretion regarding when to dispatch RDRR to avoid the need for an EEA Watch, but be required to dispatch under all EEA conditions, including a day-of EEA Watch notice.

5.4.1. Comments on Proposal

CAISO generally supports Energy Division's proposal. CAISO agrees that in order to qualify as RA, RDRR should be available for dispatch at least upon a

[200] *Id*. at 9. A third criterion for EEA 2 in Operating Procedure 4420 is that CAISO is still able to maintain minimum Contingency Reserve requirements. Failure to maintain minimum Contingency Reserve requirements triggers an escalation to EEA 3 and preparations for involuntary load drop.

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declaration of an EEA Watch by CAISO, which would allow RDRR to be available for economic dispatch in real time.[201] CAISO recognizes this approach could result in more frequent dispatch of RDRR than in the past, but asserts that it would continue to respect DR resource use limitations.[202] CAISO also clarifies that in 2018 it made a tariff clarification that allowed it to dispatch RDRR *before* seeking emergency assistance from other balancing areas. Prior to this change, RDRR was only eligible for dispatch immediately prior to canvassing other balancing authorities.[203]

CLECA, SCE and Vistra oppose Energy Division's proposal. CLECA asserts that if RDRR were dispatched in advance of an EEA Watch that it would be a dramatic change from current dispatch rules. CLECA also asserts that the current approach is consistent with the 2010 settlement agreement that was approved in D.10-06-034, and cautions that calling RDRR too soon could lead to customer fatigue and reaching dispatch limits unnecessarily.[204]

SCE argues that the Energy Division's proposal could lead to attrition and thereby jeopardize reliability, as RDRR participants agreed to participate in the program with the understanding that it would be used as a last resort, and that the proposal would essentially make RDRR resources the same as all other resources with the likelihood of more frequent dispatch.[205] SCE also asserts that Energy Division's proposal would upend the 2010 settlement, which SCE argues established that RDRR would be used as a last resort only before canvassing

[201] CAISO Opening Comments at 9.

[202] *Id.*

[203] *Id.* at 10.

[204] CLECA Opening Comments at 3-9.

[205] SCE Opening Comments at 6.

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other balancing authorities.[206] SCE further states that if Energy Division intends for RDRR resources to be reverted to load modifying resources, SCE would support exploring that change but asserts it would be more appropriately considered in the DR proceeding.[207]

Vistra is concerned that calling on RDRR during an EEA Watch may be a premature use of "emergency" DR, as EEA Watch is more likely to be noticed when the concern does not materialize even without intervention.[208] Vistra states that its support for the proposal would be contingent upon only allowing CAISO to have the ability to call resources and if Vistra's proposal on bid limits is adopted, which would ensure RDRR wouldn't inappropriately suppress scarcity price signals.[209]

PG&E appreciates the rationale behind Energy Division's proposal, but observes that it may be operationally challenging or infeasible for certain RDRR participants to participate in earlier or longer duration dispatches, which could result in customer attrition or reduction in RDRR performance.[210]

MRP understands Energy Division's intention to have resources available before an emergency is declared, but has concerns that if RDRR were dispatched earlier, there could be risk that RDRR would be used as a market price manipulation product instead of a reliability product.[211]

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[206] *Id.*

[207] *Id.* at 7.

[208] Vistra Opening Comments at 30.

[209] *Id.*

[210] PG&E Opening Comments at 15.

[211] MRP Opening Comments at 24.

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5.4.2. Discussion

Based on the information in Energy Division's proposal, the Commission is persuaded that RDRR as currently dispatched is being underutilized and is not delivering the same reliability value that we expect from RA-qualifying resources. The Commission's overriding objective for RDRR is that it should be available to mitigate or avoid an emergency grid reliability condition.

The Commission agrees that additional consideration of Energy Division's full proposal is necessary before adoption and therefore, we decline to adopt the proposal as written at this time. That said, we find that clarification of the role of RDRR in maintaining reliability under current rules and structures is warranted here.

In D.10-06-034 (RDRR Settlement Decision), the Commission adopted a settlement in which CAISO enabled RDRR bids to be available for dispatch before CAISO emergency measures are engaged.[212] In D.18-11-029, affirming the RDRR settlement, we clarified the appropriate dispatch order under CAISO's (now defunct) Alert, Warning, Emergency (AWE) system.[213]

Here, the Commission is faced with a similar question of when and how to appropriately dispatch RDRR. Due to the transition from the AWE system to NERC's EEA protocols, clarification is warranted as to what stage in the EEA sequence RDRR should be deployed. Based on the rationale articulated in D.10-06-034 and affirmed in D.18-11-029, we maintain that RDRR as a reliability

[212] D.10-06-034 at 14.

[213] D.18-11-029 at 40.

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resource should be deployed before non-RA emergency resources in order to qualify for RA.[214]

Under CAISO's current operating procedures, RDRR is characterized as an emergency-triggered resource, and as such can only be enabled into the market during EEA 1. When RDRR is dispatched according to conditions in the real-time market, CAISO therefore must escalate its grid emergency status to EEA 2 pursuant to its interpretation of NERC protocols. This dispatch practice is inconsistent with the Commission's principle that RDRR should be available before non-RA emergency resources in order to qualify for RA. To provide consistency between the Commission's established principle for RDRR and CAISO's dispatch practices, the Commission clarifies that CAISO should be allowed to use RDRR, as an RA resource, for economic or exceptional dispatch upon the declaration of a day-of EEA Watch (or when a day-ahead EEA Watch persists in the day-of). We note that this is consistent with part of Energy Division's proposal to align the trigger to a day-of EEA Watch as a condition of RA-eligibility, which is supported by CAISO.

This clarification also addresses the concerns of some parties, such as CLECA, SCE, PG&E, and Vistra, that additional use of RDRR could result in customer fatigue and/or program attrition. We note that a day-of EEA Watch is only called when CAISO forecasts an energy deficiency of one or more hours later in the day, which is a condition we have determined should enable

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[214] *See* D.10-06-034 at 13; D.18-11-029 at 40. In D.10-06-034, the Commission provided that:

> A goal of this new [RDRR] product is to improve the cost-effectiveness of reliability-triggered DR by enabling it to work better in the CAISO's dispatch sequence. Specifically, a reliability-triggered DR product should enable the CAISO to use this resource before buying "exceptional dispatch" energy or capacity. (D.10-06-034 at 13)

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RDRR.[215] We further note that if the RDRR trigger were later in the EEA sequence, RDRR would only be enabled to mitigate emergency conditions, not to help prevent them.

In summary, the Commission maintains that when RDRR is dispatched pursuant to conditions described in this decision, CAISO should not need to escalate its grid emergency status to EEA 2 (an emergency condition), thus ensuring that RDRR is available to avoid a reliability emergency.[216]
Because the Commission is clarifying an existing policy, this clarification is effective immediately. The Commission recognizes that one or more of the IOUs' tariffs, such as SCE's BIP tariff, may define their program triggers in a way that is inconsistent with the Commission's clarification. If tariff adjustments are needed to operationalize the RDRR dispatch trigger, an IOU is required to submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

5.5. Transmission Loss Factor and Planning Reserve Margin Adders for DR Resources

DR resources currently receive a Transmission Loss Factor (TLF) adder and a PRM adder. In 2010, the Commission determined that DR resources should be awarded a TLF adder, as these resources are supplied at the customer meter level and therefore eliminate the need to account for transmission line losses.[217] Under this method, QC values for DR resources are "grossed up" for

[215] When all other RA resources are committed, system conditions show a potential shortfall, and RDRR is needed to help maintain reliability in advance of deploying emergency, non-RA resources.

[216] We also note that even though RDRR would be enabled into the market earlier than EEA 1, the circumstances under which the emergency-triggered RDRR would be dispatched do not change.

[217] D.10-06-036 at OP 6.

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avoided line losses. The current TLFs are 3 percent for PG&E, 2.5 percent for SCE, and 2.5 percent for SDG&E. Additionally, each LSE's CEC-adjusted forecast includes a PRM adder, which only applies to system RA. In D.21-06-029, the Commission reduced the PRM adder for DR resources from 15 percent to 9 percent to remove elements corresponding with operating reserves and ancillary services, leaving a 9 percent adder for forced outages and load forecast error. In that same decision, the Commission requested the CEC-led working group make recommendations on this issue amongst others.[218]

Energy Division identifies that transmission-level losses and the PRM cannot be dispatched by CAISO.[219] Because they cannot be dispatched, they cannot be bid, and therefore are not incorporated into NQC values. As a result, in order for both adders to be counted, Energy Division must "gross up" RA filings to provide RA credits to CAISO to account for these adders. As the number of DR providers and LSEs purchasing DR has increased, the administrative complexity for Energy Division of "grossing up" and applying the adders has grown significantly, with the calculations often adding credits of only a fraction of a MW.

With regard specifically to the TLF adder, Energy Division identifies that no other distribution-connected resources receive a transmission adder, so there is an inconsistency between the treatment of DR and other resources at this time.

With regard specifically to the PRM adder, Energy Division asserts that while the current PRM adder accounts for forecast error and forced outages, DR does not lower either factor because if the CAISO does not procure to meet load,

[218] D.21-06-029 at OP 11.

[219] Energy Division Phase 3 Proposals at 19.

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there would be no DR load to curtail. Energy Division additionally notes that the CAISO has stated that there is no evidence that DR lowers the system forecast error or the system average forced outage rate.[220]

Energy Division's view is that the administrative burden of "grossing up" RA filings to account for these adders is not currently outweighed by the relatively small ratio of MW that are being processed, and that these related MW do not add to or further support reliability. Energy Division therefore proposes removing the TLF and PRM adders for DR resources.

5.5.1. Comments on Proposal

CAISO, DMM, and SDG&E support the proposal. CAISO strongly supports the proposal and asserts that DR adders over-estimate the amount of available load reduction to CAISO on stressed system days, so CAISO believes that removing the adders will help mitigate potential capacity shortfalls during critical periods.[221] CAISO also reiterates that with regard to the PRM adder, there is no evidence that supply-side DR reduces load forecast error or forced outages of other resources.[222] DMM asserts that its recent studies have shown that the adders have resulted in RA values that overestimate the availability of DR capacity.[223] DMM specifically cites that during high load days in summer 2022 bid in DR capacity (including TLF and PRM adders) averaged only 67 percent of their credited RA value.[224] SDG&E believes it would be more

[220] "Track 4 Proposals of the CAISO" in R.19-11-009, January 28, 2021, at 9.

[221] CAISO Opening Comments at 8.

[222] *Id.*

[223] DMM Opening Comments at 1.

[224] *Id.* at 1-2.

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appropriate for DR to receive a QC or ELCC-like valuation, similar to other resources, rather than receive adders.[225]

Joint DR Parties, CESA, CLECA, and SCE oppose the proposal. Joint DR Parties, CESA and CLECA believe the Commission should defer to the CEC Working Group Report on the issue of adders, as this process included significant stakeholder engagement.[226] Joint DR Parties and CLECA assert that just because CAISO does not currently include a mechanism to gross up transmission losses, as it does for distribution losses, this does not negate the fact that DR avoids transmission losses.[227] Joint DR Parties are also concerned that removal of the adders would create an inconsistency between the way supply-side DR and load modifying DR are valued, with load modifying DR essentially being more highly valued even though both resources provide load reduction.[228] CESA disagrees with the rationale that the TLF should be removed based solely on the argument that it would reduce administrative burden on Staff.[229] SCE opposes the proposal to remove the TLF adder, arguing that DR supplied at the customer meter level avoids line losses because power does not need to be transmitted across the transmission and distribution system.[230]

The CEC Report addressed both adders per Commission request in D.21-06-029. The CEC Report recommends eliminating the operating reserves and load forecast error components of the PRM adder and converting the forced

[225] SDG&E Opening Comments at 5.

[226] Joint DR Parties Opening Comments at 8, CLECA Opening Comments at 10, CESA Opening Comments at 11-12.

[227] Joint DR Parties Opening Comments at 7, CLECA Opening Comments at 9-10.

[228] Joint DR Parties Opening Comments at 7-8.

[229] CESA Opening Comments at 12.

[230] SCE Opening Comments at 12.

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outage component to a 5.8 percent multiplier in the capacity shortfall penalty as part of its recommended QC methodology, but does not opine on whether the forced outage component should be maintained if its QC methodology is not adopted.[231] The CEC Report recommends conducting a TLF study to update the TLF values, but does not take a position on whether the current values should be maintained or eliminated.[232]

5.5.2. Discussion

In D.23-04-010, the Commission stated that:

> In comments on the proposed decision, parties support revisiting the TLF adder issue in Phase 3 of the Implementation Track and we agree that additional consideration is necessary. In the interim, the Commission agrees that for the test year, the DLF and TLF adders should be retained to apply to DR.[233]

The Commission further stated in D.23-04-010 that "at this time there is insufficient record to address the PRM adder" for the 2024 SOD test year and that "[t]his issue will be considered in Phase 3 of the Implementation Track, alongside the CEC's DR Working Group Report recommendations."[234]

In D.23-04-010, the Commission stated that the crediting effort associated with the TLF adder "requires significant administrative overhead and complexity to account for a very small amount of incremental capacity value attributable to the TLF adder, often fractional MWs at the LSE level."[235] The Commission also agrees that there is a significant administrative burden on

[231] CEC Report at 45-46.

[232] *Id.* at 46.

[233] D.23-04-010 at OP 12.

[234] *Id.* at 55.

[235] *Id.* at 54.

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Energy Division Staff associated with applying the PRM adder to DR resources. The record does not demonstrate that this administrative burden for both the TLF and PRM adders is outweighed by the potential value of the relatively small amount of MW associated with the adders.

With respect to the PRM adder, the record suggests that removal of the adder is likely to enhance reliability, particularly during stressed conditions, by removing the risk that the PRM adder over-estimates the amount of capacity available to the CAISO on high system stress days. With respect to the TLF adder, we acknowledge that the Commission's Avoided Cost Calculator includes avoided transmission line losses for distributed energy resources and that the Commission is undertaking an effort in the Distributed Energy Resources Cost Effectiveness proceeding (R.22-11-013) to further study and refine the value of those avoided line losses. The Commission may revisit this issue, should a more streamlined process for incorporating TLF values into the CPUC and CAISO processes be identified in the future.

Based on this, we find it appropriate to discontinue the use of TLF and PRM adders for DR resources. Accordingly, the TLF and PRM adders will be removed for DR resources beginning with the 2024 RA compliance year and will also be removed for the 2024 SOD test year. We note that the DLF adder will be retained to apply to DR resources.

5.6. DR Availability Requirements

Current RA rules require all resources be available for a block of at least four consecutive hours on three consecutive days and must be able to run a minimum aggregate number of hours per month based on the number of hours

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that loads under CAISO control exceed 90 percent of peak demand in that month (which typically occurs during summer months).[236]

Energy Division identifies that current DR availability practice results in DR resources not being available when needed most. Energy Division cites to the DMM's report on resource performance in 2020 and 2021 that shows that a large portion of DR resource RA capacity was not available for dispatch during key peak net load hours and failed to perform when needed most under critical system conditions.[237] In addition, Energy Division identifies that regional demand reached historically high levels for a span of more than three consecutive days in 2022, (August 31–September 9), and under the existing rules, DR resources were not required to be available for the latter part of the extended high demand period.

To ensure DR resources are available when needed most, Energy Division proposes that DR resources: (1) must be available a minimum of three days per week with a minimum of four hours per day, for 24 hours per month, and (2) must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, or the Governor's Office has issued an emergency notice. For example, in the event of a dispatch on day T, the resource must be available for a minimum of four hours on each of the following days:

> (3 Days [including day of dispatch, T]) + Flex Alert Days + Additional Days of Grid Warning or Governor-Issued Emergency Notice

[236] D.05-10-042 at OP 16.

[237] "2021 Annual Report on Market Issues Performance," CAISO and Western Energy Imbalance Market Department of Market Monitoring, July 27, 2022, at 26.

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Energy Division asserts that this requirement would harmonize the availability requirements between DR resources and the needs of peak load.

5.6.1. Comments on Proposal

DMM supports removing the ability for DR resources to take fatigue outages during tight system conditions, on days with any Flex Alerts, Grid Warning or Governor-Issued Emergency Notice designations and offers that DR resources can reflect their fatigue by bidding in at lower capacity.[238] DMM suggests that this may result in increased DR resource supply during peak conditions.[239] Vistra believes the proposal would provide consistency in treatment across RA-eligible resources, and asks for clarification on whether the requirements would apply to both PDR and RDRR.[240]

CLECA, Joint DR Parties, OhmConnect and SCE oppose Energy Division's proposal. CLECA argues that the new availability requirements would undermine existing BIP program limits, which have been carefully designed to reflect participants' constraints.[241] CLECA believes expansion of availability disregards participants' constraints and threatens viability of the RDRR program.[242] CLECA also notes that DMM's proposal to bid in a lower capacity would not work for RDRR providers, whose load is either on or off.[243] CLECA

[238] DMM Opening Comments at 3-4.

[239] *Id*.

[240] Vistra Opening Comments at 33.

[241] CLECA Opening Comments at 10.

[242] *Id*. at 13.

[243] CLECA Reply Comments at 7.

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also believes the DR proceeding would be the more appropriate venue for considering such a proposal where it can be considered more holistically.[244]

Joint DR Parties and OhmConnect are concerned that the proposal lacks important implementation details that would create challenges for DRPs. For example, DRPs do not know that a Flex or Emergency Alert would be called before it happens and so it would be virtually impossible for a DRP to ensure that its capacity is offered in the day-ahead market ahead of an alert.[245] PG&E also expresses concern with this potential outcome. [246] The Joint DR Parties recommend that availability requirements be defined in such a way that DRPs know precisely when they are required to bid into the day-ahead market relatively well in advance of the close of bidding.[247]

SCE opposes the proposal, stating that RDRR resources are a resource of last resort because its participants are engaged in manufacturing food and medical products, supporting transit and port operations and are involved in other critical functions.[248] SCE also expresses concern that imposing these new requirements could have unintended and adverse policy ramifications including undermining the 2010 settlement agreement, the RDRR requirements and grid reliability.[249] It cites as an example the rate of customer attrition resulting from multiple emergency dispatches during the 2000-2002 Energy Crisis.[250]

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[244] CLECA Opening Comments at 11.

[245] Joint DR Parties Opening Comments at 9, OhmConnect Reply Comments at 4.

[246] PG&E Opening Comments at 15.

[247] Joint DR Parties Opening Comments at 10.

[248] SCE Opening Comments 6.

[249] *Id.* at 5-6.

[250] *Id.* at 8.

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5.6.2. Discussion

We agree with Energy Division that the Commission's DR availability requirements should help ensure that DR resources are available when the grid needs them most. While the existing DR availability requirements may have been sufficient to meet this criterion in the past, it is clear that adjustments are needed in order for DR to be available during the types of prolonged weather events we have experienced in recent years.

While we acknowledge parties' concerns that the additional requirements may create some challenges for certain DR participants, the instances in which the additional availability will be needed are limited and the need for the resources in those moments outweighs the potential for certain providers to be unable to perform.

We therefore adopt Energy Division's proposal to maintain the existing availability requirements and to add the requirement that DR resources must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, or the Governor's Office has issued an emergency notice. This requirement is effective beginning with the 2024 RA compliance year. We clarify here that the term "Grid Warning" refers to the notifications issued under CAISO's EEA system and as implemented under the Procedure for System Emergencies and Operating Procedure for Emergency Notice.[251]

The Commission recognizes the operational constraints of certain industrial and manufacturing processes that may not be able to completely cease their operations. We therefore exempt RDRR resources from the requirement at

[251] CAISO Operating Procedures RC04010 and 4420, respectively.

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this time. The Commission also acknowledges parties' concerns about submitting timely bids to meet this requirement. To that end, we specify that resources must be available during events for which alerts, notifications, and/or warnings are issued prior and up to the 10 a.m. day-ahead market deadline. For example, if a resource is dispatched and is performing between Monday, September 4 to Wednesday, September 6, and a Flex Alert is issued at 10 a.m. on Wednesday, September 6, the resource must be available for the additional days during which the Flex Alert is issued (*e.g.*, September 4-7).

We also acknowledge that many of the existing PDR resources (including long-start resources) may not be available or may be unable to submit timely bids if alerts, notifications, and/or warnings are issued after the 10 a.m. day-ahead market deadline. We will continue to monitor whether PDR resources are available when they are needed most and will consider enhancements, including adding requirements in response to day-ahead and/or real-time conditions, as appropriate in the future.

To implement this requirement, LSEs shall include contract language that DR resources: (1) must be available a minimum of three days per week with a minimum of four hours per day, and (2) must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning or EEA notification, or the Governor's Office has issued an emergency notice (the resource must be available for the duration of an Alert, Warning, or Notice that is issued prior and up to the 10 a.m. day-ahead market bid deadline).

5.7. Treatment of Late Requests of DR Monthly NQC

Energy Division identifies that DRPs frequently submit filings later than the deadline established in the RA guidelines for submitting monthly DR NQCs,

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which creates negative cascading effects for Energy Division Staff in its review and processing of these filings. To address this and minimize administrative burden, Energy Division proposes that DR NQC filings be made the first business day of the month two months prior to the requested month. As an example, under this approach, the submission deadline for the August 2023 RA showing would be June 1, 2023. Energy Division also proposes that failure to meet the deadline requirements would disqualify the month-ahead supply plan request.

This issue was not commented on by parties. The Commission finds that Energy Division's proposal is reasonable and will improve administrative efficiency of the RA program. We therefore adopt the requirement that, effective immediately, DR NQC filings must be made the first business day of the month two months prior to the requested month. Failure to meet the deadline requirements will disqualify the DRP's month-ahead supply plan request.

5.8. Treatment of DR Resources Failing to Perform During Testing

Current Commission rules require specific testing requirements for third-party DR resources procured by all non-IOU LSEs, including that:

- The DR resource must be dispatched for four consecutive hours in the RA window at least once every quarter, with dispatches fulfilled either through a CAISO market dispatch or an out-of-market test.
- The quarterly dispatch must be performed at the Resource ID level and concurrently within the same Sub-Load Aggregation Point (Sub-LAP).
- Dispatch performance results must be averaged over the four consecutive hours for each day.[252]

[252] D.20-06-031 at OPs 13, 14.

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Energy Division observes that current test levels do not demonstrate that DR resources are performing reliably.[253] Energy Division's assessment is based on available 2022 test performance results, which were low in comparison to monthly supply plans, with actual performance ranging from 27 to 35 percent of what was shown in supply plans in Q2 of 2022 and from 23 to 58 percent of what was shown in supply plans in Q3 2022. In addition, Energy Division also identifies that DRPs are not submitting an updated filing when the resource portfolio falls below the threshold of 20 percent or 10 MW less than the assigned QC value, as required by D.20-06-031.

To address this underperformance, Energy Division proposes derating non-IOU DR resources procured from third-party DRPs that are unable to achieve their stated capacity in their test performance. Specifically, in order to account for the weather-dependent nature of DR, Energy Division proposes to apply derates that correspond to their respective performance during test events for a particular quarter. The average performance results for each quarter would inform the capacity awarded through the LIPs for the respective sub-LAP. For example, a 50 percent performance in Q1 2023 may lead to a corresponding derate of up to 50 percent in the Q1 2024 capacity awarded through the LIPs as filed in April 2023. In addition, Energy Division proposes that capacity could be further adjusted based on other relevant factors such as market dispatch performance results and reasonable enrollment forecasts. These adjustments would be assessed under the current LIP process.

[253] Energy Division Phase 3 Proposals at 24.

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5.8.1. Comments on Proposal

DMM and Vistra support Energy Division's proposal. DMM agrees that incorporating test results in capacity awards would be a useful tool for improving the reliability of DR resources by incentivizing resources to provide accurate capacity estimates and to perform better when dispatched.[254] DMM believes that the lack of penalties associated with performance may explain why supply plan DR resources only curtail around 50 percent of their scheduled load reduction on high load days.[255] DMM also asserts that DR resources that consistently fail to fully deliver their scheduled load curtailments should have their capacity awards lowered to better reflect the actual amount of RA the resource provides.[256] Vistra argues that making this change will ensure that DR does not undermine reliability by overcounting its contribution.[257]

Joint DR Parties and OhmConnect oppose Energy Division's proposal. They believe it is premature to adopt the proposal because it conflicts with the CEC's DR QC counting proposal, which contains a penalty mechanism.[258] They also state that the proposal discriminates against third-party DR, as it does not address the issue of under-delivery for IOU DR programs, and it is based on only a limited set of test data encompassing only Q2 and Q3 2022.[259]

[254] DMM Opening Comments at 2.

[255] *Id.* at 2-3.

[256] *Id.* at 3.

[257] Vistra Opening Comments at 31.

[258] Joint DR Parties Opening Comments at 10-11, OhmConnect Reply Comments at 4-6.

[259] *Id.*

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5.8.2. Discussion

It is clear from the test results referenced in Energy Division's proposal that third-party DR is not performing reliably in comparison to monthly supply plans. Performance in the range from 25 to 50 percent of what is on the supply plans is not an acceptable level of performance. We agree with DMM that incorporating test results in capacity awards could incentivize resources to provide accurate capacity estimates and to perform better when dispatched so that they can become a more reliable RA resource.

With regard to the concerns raised by Joint DR Parties and OhmConnect, as discussed above, this decision does not adopt the CEC's recommendations from its DR QC Working Group Report, so currently there is no alternative mechanism for improving the reliability of third-party DR resources. The Commission also acknowledges these parties' concern regarding differential treatment of DR resources managed by IOUs versus those managed by third parties and that the proposed adjustments only apply to third parties. We do, however, also acknowledge DMM's comment that IOU DR resources appear to have met a majority of the scheduled load reductions.[260]

We find that Energy Division's proposal to enforce performance requirements by derating the QC of third-party DR resources based on their performance during test events relative to their QC values will incentivize better performance and lead to more accurate representation of the actual amount of RA that third-party DR resources provide. We therefore adopt Energy Division's proposal to consider test performance failures when making capacity awards to non-IOU DR resources procured by third-party DR providers under the LIPs.

[260] DMM Opening Comments at 2.

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This requirement is effective beginning with the capacity awards granted through the LIP process for the 2024 RA compliance year. Derates will be applied so that they correspond to performance during test events for the most recently available quarterly test results at the time of the award for the relevant quarter. The average performance results of each quarter will inform the capacity awarded through the LIPs for the respective sub-load aggregation point.

6. Summary of Public Comments

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

7. Comments on Proposed Decision

The proposed decision of ALJs Chiv and O'Rourke in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 14, 2023 by: AReM and Regents of the University of California (UC) (jointly, AReM/UC), CAISO, CalCCA, CCCE, CESA, Clean Power Alliance of Southern California and Peninsula Clean Energy Authority (jointly, Joint CCAs), CLECA, CEDMC/CPower, East Bay Community Energy (EBCE), GPI, IEP, Leap Power, Inc. (Leap), MCE, Microsoft, MRP, OhmConnect, PG&E, SCE, Shell and Vistra. Reply comments were filed on June 19, 2023 by: AReM/UC, CAISO, Cal Advocates, CalCCA, CEERT, CLECA, CEDMC/CPower, DMM, IEP, Leap, MRP, PG&E, SCE, Shell, Valley Clean Energy Alliance (VCE), and WPTF.

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All comments have been carefully considered. Significant aspects of the proposed decision that have been revised in light of comments are mentioned in this section. However, additional changes have been made to the proposed decision in response to comments that may not be discussed here. We do not summarize every comment but focus on major arguments made in which the Commission did or did not make revisions in response to party input. We remind parties that under Rule 14.3(c), comments on a proposed decision must focus on factual, legal, or technical errors in the proposed decision; comments that fail to meet the requirements will be accorded no weight.

CAISO, Microsoft, and MRP comment that the PRM should not be adopted for 2025 at this time, stating generally that there is uncertainty regarding the results of the PRM calibration process for the SOD framework and insufficient record to ensure the PRM and effective PRM are reasonable for 2025.[261] IEP asserts that the Commission should allow the possibility of modifying the PRM in 2025 in light of market developments.[262] Cal Advocates responds that there will be uncertainty with implementing the SOD framework and that applying a 17 percent PRM for 2024 and 2025 provides a counter-balance of certainty for LSE's procurement planning, as changing the 2025 PRM in early 2024 gives LSEs little time to adjust procurement planning.[263] MRP requests Energy Division publish the results of the conversion tool to establish the PRM for the SOD framework, as it is unclear whether the traditional PRM from the LOLE study would ensure reliability under a SOD framework.

[261] CAISO Opening Comments on Proposed Decision at 1, Microsoft Opening Comments on Proposed Decision at 11, MRP Opening Comments on Proposed Decision at 8.

[262] IEP Opening Comments on Proposed Decision at 2.

[263] Cal Advocates Reply Comments on Proposed Decision at 2.

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For the reasons stated in the decision, the Commission finds it reasonable and prudent to adopt a PRM of 17 percent and the effective PRM for the 2024 and 2025 RA years, and declines to modify the decision. As stated in D.23-04-010 at Ordering Paragraph 14, after Energy Division modifies the SOD calibration tool, Energy Division will publish the draft calibration tool on the Commission's website and solicit informal party comments.

PG&E comments that D.21-12-015 required IOUs to file non-binding month-ahead RA filings, as part of the adoption of the effective PRM.[264] PG&E recommends removing this requirement, stating that the original intent of this was to provide insight into contracted RA resources so state agencies could develop a better understanding of supply conditions and that this need no longer exists. The Commission concludes that the non-binding month-ahead RA filings continue to provide important information to assess market supply conditions and declines to modify this requirement from D.21-12-015.

Numerous parties, including AReM/UC, CalCCA, CCCE, EBCE, MCE, Shell, and VCE, oppose the LSE expansion rule for various reasons.[265] CalCCA argues that the expansion rule exceeds the Commission's jurisdiction over CCA implementation plans generally and that basing the "earliest possible date" on an LSE's compliance history exceeds statutory authority to address cost shifts between groups. CCCE asserts that the expansion rule exceeds the Commission's authority under AB 117 and D.05-12-041. Shell comments that the

[264] PG&E Opening Comments on Proposed Decision at 2.

[265] AReM/UC Opening Comments on Proposed Decision at 2, CalCCA Opening Comments on Proposed Decision at 2, CCCE Opening Comments on Proposed Decision at 3, EBCE Opening Comments on Proposed Decision at 2, MCE Opening Comments on Proposed Decision at 2, Shell Opening Comments on Proposed Decision at 1, VCE Reply Comments on Proposed Decision at 1.

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Commission has no statutory authority to curtail retain choice. AReM/UC argue that Section 366.2 is limited to CCAs and does not apply to ESPs.

CCCE and CalCCA contend that there is no evidence demonstrating a cost shift from deficient LSEs to compliant LSEs, and CalCCA states that there is no evidence that deficient LSEs rely on other LSEs' procurement or that allowing deficient LSEs to expand is detrimental to grid reliability. CalCCA and Shell argue that the expansion rule is discriminatory to non-IOUs because the rule does not apply to IOUs as their territories do not expand and IOUs are required to serve any new customer that requests service.

The Commission disagrees that Sections 366.2 or Section 365.1 constrain the Commission's ability to ensure CCAs seeking to expand service are capable of meeting their RA requirements. The Commission has statutory obligations to ensure energy reliability at just and reasonable rates and specific authority to ensure RA compliance. While the Public Utilities Code includes some specific sections regarding CCA certifications, our approach harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2. Both CCA and ESP related statutes provide ways for the Commission to revoke the ability of such LSEs to operate if it shows the LSEs are unable to effectuate their primary functions of serving customer load consistent with their Commission-allocated RA obligations. Under the rule adopted today, the Commission does not claim an ability to revoke an LSE's authority to operate, but merely to ensure it may not expand if an LSE cannot satisfy its minimum RA procurement requirements as demonstrated by compliance failures. As discussed above, the Commission has clear statutory authority to ensure energy supply reliability and the inability (and in many instances, repeated inability) of some LSEs to meet minimum

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procurement requirements implies business choices that must take into account each LSE's duty to provide a reliable energy supply for its customers.

As discussed above, the expansion rule does not discriminate against CCAs and ESPs, rather it provides consequences for those CCAs and ESPs that fail to meet statutorily directed minimum reliability requirements expected of all LSEs and that lean on the procurement of other LSEs to provide energy for customers. Section 380, and the Commission's prior decisions interpreting it and related statutes, provide substantial evidence that failure to meet RA requirements threatens grid reliability. Accordingly, we decline to remove the LSE expansion requirement adopted in this decision.

AReM/UC and Shell argue that the expansion rule should only apply to future deficiencies as LSEs should not be sanctioned for past conduct that occurred before the rule was adopted.[266] We provide clarification that only prospective RA deficiencies accrued after the effective date of this decision will apply to the adopted expansion requirement. In other words, the first RA year-ahead deficiencies to be applied will be the 2024 year-ahead filing due on October 31, 2023, and the first month-ahead deficiency to be applied will be the September 2023 month-ahead filing. The decision has been modified with this clarification.

AReM/UC and Shell recommend that the expansion rule be limited to 24 months, not two calendar years, because CCAs typically enroll new service territories in January while ESP customer enrollment is staggered.[267] The

[266] Shell Opening Comments on Proposed Decision at 12, AReM/UC Opening Comments on Proposed Decision at 2.

[267] AReM/UC Opening Comments on Proposed Decision at 9, Shell Opening Comments on Proposed Decision at 12.

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Commission declines to modify the two-year retrospective analysis of RA compliance. RA requirements are based on an annual cycle and a binding load forecast must be submitted to meet year-ahead requirements for the year of an LSE's proposed expansion. Further, the Commission seeks to avoid potential willful gaming of compliance timelines.

AReM/UC and EBCE proposes that the rule only apply to deficiencies greater than 1 percent of an LSE's procurement requirement, similar to the threshold in the RA penalty point structure adopted in D.21-06-029, or using a 2.5 percent threshold, as proposed by Energy Division.[268] EBCE comments that the rule should only apply to substantive RA deficiencies and not to deficiencies that are cured by the LSE within five days after Energy Division's notification of the deficiency. In D.21-06-029, we adopted a rule that if an LSE's month-ahead deficiency "is less than 1% of the LSE's system RA requirements, no points will be accrued."[269] The Commission finds it reasonable that the 1 percent threshold adopted in D.21-06-029 should apply to the expansion requirement as well. We note that an LSE that incurs any system RA deficiency, even less than 1 percent of its system requirements, is still subject to the RA penalty process, as established in past Commission decisions. The decision has been modified with this change.

The Commission clarifies that deficiencies cured within five business days from the date of notification by Energy Division will not count towards the expansion rule. The Commission agrees that administrative deficiencies will not count towards the expansion rule. In D.11-06-022, modifying in part Resolution

[268] AReM/UC Opening Comments on Proposed Decision at 7, EBCE Opening Comments on Proposed Decision at 2.

[269] D.21-06-029 at OP 16.

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E-4195, the Commission adopted "Specified Violations," as distinct from substantive RA deficiencies. "Specified Violations" include an LSE's failure to file historic load data and file load forecasts in the time and manner required, as well as deficiencies cured within five business days from the date of notification by Energy Division. These "specified violations" will not be applied to the expansion rule adopted here. The decision has been modified with these changes.

AReM/UC, Joint CCAs, and MCE comment that the expansion rule should only apply to month-ahead deficiencies, not year-ahead deficiencies.[270] AReM/UC and MCE argue that year-ahead deficiencies that are eventually cured do not jeopardize system reliability, while Joint CCAs state that month-ahead deficiencies are a more realistic measure of reliability. Joint CCAs and MCE add that applying month-ahead deficiencies would incentivize LSEs to cure year-ahead deficiencies in the month-ahead timeframe.

The Commission agrees (with some caveats) that if an LSE "cures" its year-ahead RA deficiency in the month-ahead timeframe, the year-ahead deficiency will not be applied to the adopted expansion rule. However, this only applies to a year-ahead deficiency accrued two years before the year in which the LSE files its binding load forecast. To illustrate, Year 0 (Y0) is the year that an LSE files its binding load forecast with additional load it will serve. An LSE must meet its year-ahead and month-ahead requirements in the two years before Y0 (that is, Year Minus 1 (Y-1) and Year Minus 2 (Y-2)). If an LSE receives a year-ahead deficiency in Y-2 and "cures" that deficiency in the month-ahead process in Y-1, the Commission finds it reasonable to remove the Y-2 deficiency from applying

[270] Joint CCA Opening Comments on Proposed Decision at 3, MCE Opening Comments on Proposed Decision at 2, AReM/UC Opening Comments on Proposed Decision at 7.

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to the expansion rule. A year-ahead deficiency in Y-1, however, will necessarily apply to the expansion rule because there is insufficient time for the LSE to cure the Y-1 deficiency in the Y0 month-ahead timeframe, as the LSE will have filed its binding load forecast commitments. Accordingly, the decision is modified with these changes and the following table is adopted:

System RA Deficiencies That Apply to the LSE Expansion Requirement	
Year Plus 1 (Y+1)	Year that an LSE elects to expand
Year 0 (Y0)	Year that an LSE files its April load forecast
Year Minus 1 (Y-1)	(1) Month-Ahead deficiencies apply (2) Year-Ahead deficiency (for Y0) applies *Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1.
Year Minus 2 (Y-2)	(3) Month-Ahead deficiencies apply (4) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1

AReM/UC and Shell seek clarification about the definition of "new customers" or "new direct access customer."[271] AReM/UC recommend "new direct access customer" be defined as "one new to the DA program, *i.e.* entering the DA program from IOU or CCA service via the DA lottery without any existing DA service accounts." Shell recommends that "new Direct Access customers" should not include existing ESP customers that are adding a new service account or switching from one ESP provider to another. These parties state that this would be more consistent to treatment of CCAs that can expand

[271] AReM/UC Opening Comments on Proposed Decision at 8, Shell Opening Comments on Proposed Decision at 12.

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their customer base in existing territories, and would resolve ambiguity regarding customer relocations, which should not be treated as a new customer.

The Commission clarifies that an ESP's existing customers may experience load expansion, relocation, and changes in their service accounts (including adding new accounts from the ESP's existing customers) during the expansion pause period. However, ESPs may not take on customers switching from another ESP or entering the DA program from IOU or CCA service via the DA lottery. The decision has been modified with this clarification.

AReM/UC comment that the decision refers to ESPs not being able to "enroll any new customers" and later than ESPs are restricted from "signing new direct access customers."[272] AReM/UC state that ESPs may have signed contracts before the rule was in place with customer enrollment dates that begin after the restriction. AReM/UC recommend that the rule should not apply to ESP enrollments for contracts signed before an ESP incurs a deficiency that triggers the restriction. As discussed above, the Commission has modified the decision to apply to prospective RA deficiencies following the effective date of this decision. We maintain that the rule will apply to the signing of direct access customers after the effective date of this decision.

Several parties oppose using an LSE ID for non-resource specific RA imports. CAISO asserts it is infeasible to implement because import resource IDs only include a Scheduling Coordinator ID and there is no association between resource IDs and LSE IDs in the Master file registration process.[273] CAISO adds that it generates import resource IDs for all import resources, not just those

[272] AReM/UC Opening Comments on Proposed Decision at 10.

[273] CAISO Opening Comments on Proposed Decision at 9.

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contracted with LSEs for RA, and import RA IDs may represent capacity with several LSEs and potentially non-RA capacity. Instead, CAISO suggests that it and Energy Division work to identify what additional data could help Energy Division's compliance concerns. CCCE argues that requiring an LSE ID is at odds with how RA imports are executed in the market and if real-time substitutions must be duplicated over many resource IDs, this will likely reduce the supply of import RA.[274] WPTF agrees that using LSE IDs would increase administrative burdens and operational costs for import suppliers, reducing the import supply to California.[275]

In considering CAISO's comments, the Commission agrees it is not feasible for CAISO to incorporate LSE IDs for RA imports at this time, and we agree that the requirement should be removed from the decision. Rather, the Commission authorizes Energy Division to work with CAISO to identify the appropriate resource ID registration process that will allow non-resource specific RA import IDs to be mapped to the contracted LSE, when the LSE is not the scheduling coordinator. Energy Division should further investigate the real-time market reliability and liquidity concerns raised by parties, and submit a proposal into the RA proceeding as warranted. The decision is modified with these changes.

CalCCA and CCCE seek clarification as to when an LSE goes from Tier 2 in the year-ahead filing down to a Tier 1 in a month-ahead filing, which could occur where penalty points expire after two years.[276] CalCCA recommends all year-ahead deficiencies be penalized at the Tier 1 price and the balance collected in the

[274] CCCE Opening Comments on Proposed Decision at 6.

[275] WPTF Reply Comments on Proposed Decision at 4.

[276] CalCCA Opening Comments on Proposed Decision at 15, CCCE Opening Comments on Proposed Decision at 7.

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month-ahead process when the LSE moves down a tier. CCCE recommends a formula where year-ahead penalties are charged at the Tier 1 price; then, for the month-ahead penalty, an LSE pays the difference between the month-ahead penalty and Tier 1 penalty already paid on its year-ahead deficiency, plus the current tier price on any incremental month-ahead deficiency.

The Commission finds CCCE's recommended formula below to be reasonable and the decision is modified to include this formula.

$$\text{Year-Ahead penalty} = \text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier 1 Price}$$

$$\text{Month-Ahead penalty} = [(\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier Price}^{\text{Month-Ahead}}) - \text{Year-Ahead penalty}] + (\text{Deficiency}^{\text{Month-Ahead incremental}} \times \text{Tier Price}^{\text{Month-Ahead}})$$

AReM/UC, CalCCA, and Shell oppose eliminating the monthly true-up and state that there are instances where a monthly true-up is needed to prevent large cost shifts.[277] AReM/UC state that while the load change amount may be a small fraction of overall system demand, to a small LSE this may have a large impact to their total demand. Shell and AReM/UC suggest allowing monthly true-ups if the migrating load is greater than 50 MW. While the Commission understands the issue of cost shifts may have larger impacts on smaller LSEs, we find that allowing monthly true-ups for 50 MW of migrating load or greater for all LSEs will continue to burden Commission Staff. We decline to adopt this threshold. However, recognizing parties' concerns with eliminating the load forecast update entirely, we find it reasonable to allow one load migration update in February to cover May to December load migration, similar to the local

[277] AReM/UC Opening Comments on Proposed Decision at 14, Shell Opening Comments on Proposed Decision at 13, CalCCA Opening Comments on Proposed Decision at 14.

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and flexible RA true-up process today. The decision has been modified to reflect this.

SCE recommends removing the modified confidentiality matrix, stating that it is unnecessary and adds administrative and compliance challenges for utilities, especially when the modifications do not substantively change the existing matrix.[278] PG&E disagrees and argues that the modifications to the matrix are necessary to define the more narrow protections that apply to information being requested for transparency.[279] PG&E states that without the modifications to the matrix, the bid and offer data requested would be defined as confidential information. The Commission agrees with PG&E and declines to modify the decision.

CEDMC/CPower, CLECA, CESA, Leapfrog, and Shell oppose a PDR bid cap and request a $949/MWh PDR bid cap, if the Commission determines a bid cap is needed.[280] CLECA asserts that $949/MWh is warranted as each PDR has an opportunity cost that may be dynamic and may exceed the proposed $500/MWh cap. CLECA also specifically recommends the $949/MWh bid cap be applied year round.[281] CESA argues a $949/MWh bid cap will achieve the Commission's goal for PDR to be dispatched before RDRR.[282] CEDMC/CPower identify that a $949/MWh minimizes the potential that PDRs may reach their

[278] SCE Opening Comments on Proposed Decision at 10.

[279] PG&E Reply Comments on Proposed Decision at 3.

[280] CEDMC/CPower Opening Comments on Proposed Decision at 8, CLECA Opening Comments on Proposed Decision at 16, CESA Opening Comments on Proposed Decision at 2, Leapfrog Opening Comments on Proposed Decision at 3-4, Shell Reply Comments on Proposed Decision at 3-4.

[281] CLECA Opening Comments on Proposed Decision at 13.

[282] CESA Opening Comments on Proposed Decision at 3.

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dispatch limit before periods of most critical need. [283] Upon further consideration, we agree with parties that it is appropriate at this time to establish a PDR bid cap of $949/MWh, as this level will help ensure a more rational dispatch order and would minimize the potential of excluding resources that may have varying marginal costs from participating in the market when needed most. While it is appropriate to adopt a $949/MWh PDR bid cap at this time, we intend to revisit this requirement as needed and as more information is gathered on PDR bidding behavior and dispatch. We emphasize that the PDR bid cap is a cap and not a floor, and that supply-side DR resources are expected to competitively bid into the CAISO wholesale market, consistent with the Commission's DR principles adopted in D.16-09-056. The Commission has modified the decision with this change.

PG&E agrees with the exemption from the PDR bid cap for DRAM resources for 2024 and requests that consideration of whether to apply the PDR bid cap to DRAM resources after 2024 be deferred to the DR proceeding.[284] We decline to make this change, as the intention of this decision is for the bid cap to apply to all PDRs that are required to be dispatched into the real-time market.

CEDMC/CPower and SCE identify that long-start PDRs are not required to bid into the real-time market, and request the decision clarify that the bid cap proposal does not represent a requirement for long-start PDRs to bid or schedule into the real-time market for hours they are not already dispatched.[285] We agree

[283] CEDMC/CPower Opening Comments on Proposed Decision at 8.

[284] PG&E Opening Comments on Proposed Decision at 3.

[285] CEDMC/CPower Opening Comments on Proposed Decision at 7; SCE Opening Comments on Proposed Decision at 8.

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that this clarification is warranted and the decision has been updated to reflect this.

CEDMC/CPower, CLECA and SCE oppose the Commission's clarification on the appropriate RDRR dispatch trigger. SCE specifically asserts that there is no support in the record of this proceeding or in D.10-06-034 or D.18-11-029 to support the Commission's principle that RDRR, as a reliability resource, should be deployed before non-RA resources.[286] SCE further argues that RDRR should not be read to harmonize with non-RA emergency resources that were created after the 2010 settlement and D.18-11-029.[287] CLECA agrees with SCE's assertion and argues D.10-06-034 contemplated more stringent conditions for triggering RDRR.[288] CEDMC/CPower similarly assert that the proposed decision inappropriately converts RDRR from an emergency resource to an economic resource.[289] SCE and CEDMC/CPower also view the triggering of RDRR dispatch at an EEA Watch as inconsistent with the existing trigger.[290]

We do not modify the RDRR dispatch section based on comments. We first address parties' assertions that the principle that RDRR, as a reliability resource, should be deployed before non-RA emergency resources, is not supported. These assertions are inaccurate. The 2010 settlement specifically contemplates RDRR being deployed in advance of non-RA emergency resources when it identifies that RDRR should be dispatched prior to CAISO canvassing

[286] SCE Opening Comments on Proposed Decision at 2.

[287] *Id.* at 3.

[288] CLECA Opening Comments on Proposed Decision at 4.

[289] CEDMC/CPower Opening Comments on Proposed Decision at 9.

[290] SCE Opening Comments on Proposed Decision at 3, CEDMC/CPower Opening Comments on Proposed Decision at 10.

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neighboring balancing authorities for available exceptional dispatch energy or capacity.[291] We next address the assertion that prior decisions would not allow RDRR dispatch to be harmonized with non-RA emergency resources that were created after D.10-06-034 and D.18-11-029. We disagree. The 2010 settlement describes the features of reliability-based DR programs to which the settlement would apply, indicating the Commission's intent that the settlement be harmonized with future resource offerings and not just specific offerings in existence at the time of the settlement.[292]

We also address the argument that the Commission's clarification converts RDRR from an emergency resource to an economic resource. This is similarly incorrect. As is discussed in this decision, the clarified RDRR dispatch trigger does not render RDRR a resource generally available for economic dispatch during normal system conditions, but rather maintains its availability during times of significant grid stress, which is consistent with the 2010 settlement.[293] With regard to concerns related to what stage RDRR is triggered, as discussed in this decision, the CAISO's transition to NERC protocols has necessitated a clarification of when RDRR should be appropriately dispatched, and the EEA Watch stage most appropriately aligns with the Commission's principle that RDRR be deployed before non-RA emergency resources. Finally, CAISO, a signatory to the settlement, states that it supports the Commission's clarification of the RDRR dispatch trigger, and its understanding that RDRR resources should be available for use to prevent emergency conditions rather than only after an

[291] D.10-06-034, Appendix A at Section A(4)(l).

[292] D.10-06-034 Appendix A, Settlement at 2.

[293] D.10-06-034 Appendix A, Settlement at Section A.(4)(e).

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emergency exists.[294] CAISO further asserts that it will continue to respect RDRR use limits, and would use its discretion to allow for fatigue breaks and minimum dispatch periods to avoid RDRR use during transient price spikes.[295]

CLECA, PG&E and SCE request that if the RDRR dispatch trigger is adopted, that implementation either be delayed until 2024 and/or the Commission allow participants sufficient time to opt out or change their firm service level.[296] We do not modify the decision to incorporate these requests. As the Commission is clarifying an existing definition, the operationalization is effective immediately.

SCE also identifies that tariff changes may be necessary for the IOUs to operationalize the RDRR dispatch trigger if adopted.[297] The Commission recognizes that one or more of the IOUs' tariffs, such as SCE's BIP tariff, may define their program triggers in a way that is inconsistent with the Commission's clarification. If tariff adjustments are needed to operationalize the RDRR dispatch trigger, an IOU is required to submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

CLECA asserts that no substantial additional record regarding the TLF and PRM adders has been developed since the adoption of D.23-04-010 on April 4, 2023, which retained the adders, and therefore it would be inappropriate to remove the adders in this decision.[298] The record for D.23-04-010 was

[294] CAISO Reply Comments on Proposed Decision at 4.

[295] *Id.* at 4-5.

[296] CLECA Opening Comments on Proposed Decision at 5, PG&E Opening Comments on Proposed Decision at 6, SCE Opening Comments on Proposed Decision at 5.

[297] SCE Reply Comments on Proposed Decision at 4.

[298] CLECA Opening Comments on Proposed Decision at 10-11.

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submitted in December 2022 as part of Phase 2 of the Reform Track.[299] Since that time, as part of Phase 3 of the Implementation Track, an Energy Division staff proposal, and numerous comments on the TLF and PRM adders have been submitted into the record of this proceeding, and it is upon that record that this decision makes its determination. Therefore, CLECA's concerns with the extent of the record upon which the Commission's determination was made are without merit.

With regard to the adjustments to the DR availability requirements, SCE and PG&E request that existing DR contracts be exempt from the requirement, as they believe renegotiation of those contracts would be necessary to enforce the requirement.[300] When the Commission adopts a policy that adjusts RA program rules, it may be necessary for contracts to be renegotiated in order to ensure compliance with the new rules. An exception is not warranted in this instance. We therefore decline to exempt existing contracts from the expanded availability requirements.

With regard to the treatment of DR resources failing to perform during testing, OhmConnect argues that it would be unfair to derate QC based on testing that was conducted before the adoption of this decision because participants did not have notice that the results of testing would be used for this purpose.[301] While this decision does connect test results to the LIP QC adjustment process, DRPs were already expected to provide accurate capacity estimates and to perform when dispatched, so any testing approach used by

[299] D.23-04-010 at 4.

[300] SCE Opening Comments on Proposed Decision at 6; PG&E Reply Comments on Proposed Decision at 2.

[301] OhmConnect Opening Comments on Proposed Decision at 5-6.

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DRPs should already reflect a best attempt at estimating and performing reliably, and would be appropriate to use for the purposes of QC adjustment. We therefore decline to delay implementation of the requirement.

The Commission is not persuaded by the cases cited by OhmConnect.[302] While *Stillwater Mining Co. v. Federal Mine Safety & Health Review Comm'n* provides that regulatory settings generally should provide notice of what behavior is expected, the court in that case supported the regulatory agency's imposition of a penalty using a standard of the judgment of a reasonably prudent person with knowledge of the industry would have known what was expected with regard to the specific prohibition or standard. Here, in both the CPUC and the CAISO's DR related proceedings, decisions and tariffs have made clear that DR providers are required to make reasonably reliable commitments in the RA capacity and CAISO energy markets. Knowingly overstating the capabilities of one's resources is generally understood in the energy industry as a violation of market rules.[303] With respect to its due process claim, OhmConnect has not shown here a) that it has a due process right to a particular QC valuation of its resource that testing showed to be inaccurate, or b) that the modification of QC based on resource testing after a DRP fails to update its QC capacity is not reasonably foreseeable.

8. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Debbie Chiv and Shannon O'Rourke are the assigned ALJs in this proceeding.

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[302] OhmConnect cites to *Stillwater Mining Co. v. Federal Mine Safety & Health Review Comm'n* (9th Cir. 1998) 142 F.3d 1179, among other cases.

[303] *See OhmConnect, Inc.*, Docket No. IN23-6-000, Order Approving Stipulation and Consent Agreement (May 22, 2023) 183 FERC ¶ 61,136.

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Findings of Fact

1. CAISO recommended that the existing capacity needed for all local areas is 22,080 MWs for 2024, 22,191 MWs for 2025, and 23,058 MWs for 2026.

2. CAISO recommended system-wide Flexible Capacity Requirements that range from 24,446 MWs in March to 20,018 MWs in July.

3. It is necessary to modify the RA measurement hours to align with CAISO's revised AAH window. It is appropriate to adjust the hours for the DR MCC bucket and MCC buckets 1, 2, and 3 based on revisions to the RA measurement hours.

4. Given the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years. Increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time.

5. Extending the effective PRM through 2025 is beneficial in that it provides non-binding targets for IOUs to procure contingency resources and allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.

6. Allowing LSEs that cannot meet their existing RA obligations to expand their territory or to otherwise take on new customer load is detrimental to grid reliability. LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting.

7. Additional data reporting by the CPE will help LSEs manage upfront system RA procurement and understand the inventory of available resources to assess the potential for CAISO backstop procurement. Additional transparency

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in the CPE process will also help market participants understand how the CPE framework is functioning.

8. Allowing LSEs to sell a self-shown local resource may increase the amount of self-shown resources by removing a potential disincentive for self-showing and provide additional opportunities for LSEs to procure system and/or flexible RA.

9. Limiting the additional acquisition of ATC at COB/Malin and NOB effectively ensures there is no violation of the simultaneous import limit, nor any associated reliability risk.

10. It is necessary to clarify that any penalty points accrued by an LSE will be applicable to the LSE's month-ahead and year-ahead RA penalties. It is also necessary to clarify that if an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier.

11. More transparency into LSEs' compliance with the RA program is critical to providing insight into reliability risks related to LSEs' RA deficiencies and RA program violations.

12. It is appropriate to deny local waiver requests that are filed past the deadline.

13. Directing Energy Division to provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the credits to Energy Division would provide sufficient time for Energy Division to allocate CAM and RMR credits based on the total CPUC-jurisdictional share.

14. The monthly load forecast update process requires significant Commission Staff resources, while generally resulting in only small modifications to the RA requirements. Any larger changes in load migration will be accounted for

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because CCAs are required to provide at least a one-year notice prior to implementation or expansion.

15. The CEC's supply-side DR QC proposal would benefit from further refinement and testing.

16. The existing LIPs process is imperfect.

17. CAISO inserts bids for RDRR at $950/MWh and will accept them if there are insufficient resources at a lower price.

18. Implementing a bid price cap for PDRs would prevent the possibility of an irrational dispatch order where RDRR is dispatched before PDRs and increase PDRs' contributions to reliability.

19. Extending the Prohibited Resources policy to all RA-eligible DR resources is in line with the Commission's initiating objectives in adopting the original Prohibited Resources policy in D.16-09-056 and aligns with state policy that DR resources participating in RA programs should be clean.

20. There is significant administrative burden on Energy Division Staff associated with applying the TLF and PRM adders to DR resources and a relatively small amount of MW associated with the adders.

21. Removal of the PRM adder is likely to enhance reliability, particularly during stressed conditions, by removing the risk that the adder over-estimates the amount of capacity available to the CAISO on high system stress days.

22. Adjustments are needed to the existing DR availability requirements to ensure DR is available during the types of prolonged weather events experienced in recent years.

23. DRPs frequently submit filings later than the deadline established in the RA guidelines for submitting monthly DR NQCs, which creates administrative inefficiency in review and processing of filings.

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24. Third party DR is not performing reliably in comparison to monthly supply plans.

Conclusions of Law

1. CAISO's recommended LCR study results for 2024-2026 are reasonable and should be adopted.

2. CAISO's recommended systemwide FCR figures for 2024 are reasonable and should be adopted.

3. Revised RA measurement hours for the spring month of May should be adopted.

4. Hours for the DR MCC bucket and MCC buckets 1, 2, and 3 should be adjusted based on the revised RA measurement hours.

5. A PRM of 17 percent is reasonable and prudent for the 2024 and 2025 RA years.

6. It is reasonable and prudent to maintain the effective PRM adopted in D.21-12-015 at the 2023 level for the 2024 and 2025 RA years.

7. A requirement that LSEs that have had a system RA deficiency within the prior two years cannot expand to take on new customer load is a reasonable approach and permissible under Pub. Util. Code Section 380.

8. Energy Division's proposal on additional data reporting for the CPE, with PG&E's modifications to the confidentiality matrix adopted in D.23-03-034, is appropriate.

9. It is reasonable to allow an LSE that has self-shown a local resource to the CPE to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's self-showing obligation.

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10. An LSE that procures ATC, or acquires ATC through the resale process, at either COB/Malin or NOB should be permitted to pair the ATC with RA imports to meet its RA requirements.

11. Clarifications to the penalty point system applying to year-ahead RA deficiencies and as to what month a higher penalty will apply should be adopted.

12. Energy Division's proposal to increase transparency on LSEs' RA compliance violations, with modifications, should be adopted. The information should be disclosed by CPED or Energy Division no earlier than October 1 of the compliance year.

13. Late local waiver requests should be denied.

14. During the 1st quarter of each year, Energy Division should provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the RMR credits to Energy Division.

15. It is reasonable that LSEs are allowed one load migration update in February to cover May-December load migration.

16. Energy Division should be authorized to lead a working group, with support from CEC Staff, to refine elements of the CEC's incentive-based supply-side DR QC proposal and submit a joint proposal in the RA proceeding no later than December 2024.

17. Energy Division should be authorized to pursue simplification of the current LIP requirements using a stakeholder process.

18. A PDR bid cap of $949/MWh should be adopted for both the day-ahead and real-time markets.

19. The following requirements should be adopted: (1) All RA-eligible DR resources should be required to abide by the Prohibited Resources policy as

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defined in D.16-09-056 and subsequent decision and resolutions, (2) the Prohibited Resources Verification Plan should apply to all RA-eligible DR resources, and (3) associated costs of implementation shall be recovered through the existing mechanism or through another mechanism if adopted through Application 22-05-002 et al.

20. The TLF and PRM adders should be removed for DR resources beginning with the 2024 RA compliance year and be removed for the 2024 slice-of-day test year.

21. DR availability requirements should be expanded so that resources are available when most needed.

22. DR NQC filings should be made the first business day of the month two months prior to the requested month.

23. Third-party DR QC should be derated based on performance during test events relative to their QC values.

24. Motions made in this proceeding that are not expressly ruled upon are deemed denied.

25. The proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Commission approves 22,080 megawatts as the existing capacity needed for the Local Capacity Requirement for 2024.

2. The Commission approves 22,191 megawatts as the existing capacity needed for the Local Capacity Requirement for 2025.

3. The Commission approves 23,058 megawatts as the existing capacity needed for the Local Capacity Requirement for 2026.

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4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2024 are adopted.

5. The Resource Adequacy (RA) measurement hours are modified to 5:00-10:00 p.m. for March, April, and May, and 4:00–9:00 p.m. for all other months. The modified RA hours shall be effective beginning in the 2024 RA compliance year.

6. In adopting Ordering Paragraph 5, the demand response (DR) maximum cumulative capacity (MCC) bucket and MCC bucket categories 1, 2, and 3 are modified to reflect the new Resource Adequacy measurement hours. The revised MCC buckets are as follows:

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available at least 24 hours per month from May-September. For May, must be available Monday-Saturday for 4 consecutive hours between 5 PM-10 PM. For June-September, must be available Monday-Saturday for 4 consecutive hours between 4 PM-9 PM.	8.3%
1	Monday–Saturday, at least 100 hours per month. For February, total availability is at least 96 hours. January - February, June-December, 4 consecutive hours between 4 PM - 9 PM. March-May, 4 consecutive hours between 5 PM – 10 PM.	17.0%
2	Every Monday–Saturday. January-February, June-December, 8 consecutive hours that include 4 PM–9 PM. March-May, 8 consecutive hours that include 5 PM–10 PM.	24.9%
3	Every Monday–Saturday. January-February, June - December, 16 consecutive hours that include 4 PM – 9 PM. March-May, 16 consecutive hours that include 5 PM–10 PM.	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

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7. For the 2024 and 2025 Resource Adequacy compliance years, a 17 percent planning reserve margin (PRM) and an effective PRM procurement target of 1,700-3,200 megawatts (MW) is adopted. The procurement target will be divided between the three investor-owned utilities similar to the targets adopted in Decision 21-12-015: 170-320 MW for San Diego Gas & Electric Company, and 765-1,440 MW each for Pacific Gas and Electric Company and Southern California Edison Company.

8. The requirements adopted in Decision (D.) 21-12-015 pertaining to the effective planning reserve margin (PRM) are applicable to the effective PRM adopted in Ordering Paragraph 7. Specifically, resources eligible to count towards the effective PRM will remain unchanged from D.21-12-015 and all resources that are currently eligible to be contingency resources will remain eligible to be contingency resources in 2024 and 2025.

9. A community choice aggregator (CCA) that has had a system Resource Adequacy (RA) deficiency within the prior two calendar years must first be in RA compliance for two calendar years prior to submitting an implementation plan to expand. An electric service provider (ESP) that has had a system RA deficiency within the prior two calendar years must first be in RA compliance for two calendar years prior to signing new direct access customers. These rules are applicable to load-serving entities that are not acting as the Provider of Last Resort. As to CCAs, this requirement will apply to initial or revised implementation plans submitted after the effective date of this decision. As to ESPs, this requirement will apply to direct access customers signed after the effective date of this decision. RA deficiencies accrued after the effective date of this decision will apply to this requirement. The first year-ahead deficiencies to be applied will be the 2024 year-ahead RA filing due on October 31, 2023, and the

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first month-ahead deficiency to be applied will be the September 2023 month-ahead RA filing.

10. Any year-ahead Resource Adequacy (RA) deficiency accrued in the calendar year two years prior to the year that a load-serving entity (LSE) files its binding load forecast will count towards the requirement adopted in Ordering Paragraph 9, unless the LSE cures the year-ahead RA deficiency in the month-ahead timeframe. The following RA deficiencies will apply to the requirement:

System RA Deficiencies That Apply to the LSE Expansion Requirement	
Year Plus 1 (Y+1)	Year that an LSE elects to expand
Year 0 (Y0)	Year that an LSE files its April load forecast
Year Minus 1 (Y-1)	(1) Month-Ahead deficiencies apply (2) Year-Ahead deficiency (for Y0) applies *Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1.
Year Minus 2 (Y-2)	(1) Month-Ahead deficiencies apply (2) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1

The following violations will not apply to the expansion requirement:

(1) A month-ahead or system-ahead system RA deficiency that is less than 1 percent of the LSE's system RA requirements.

(2) "Specified violations," as adopted in Resolutions E-4017 and E-4195 and modified in Decision 11-06-022.

11. To implement the requirements adopted in Ordering Paragraph 9, Energy Division is authorized to review Resource Adequacy (RA) enforcement referrals and/or citations issued by the Consumer Protection and Enforcement Division, including confidential versions, for the prior two years to determine if a load-

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serving entity (LSE) is eligible to expand. Energy Division will review and confirm compliance with the adopted requirements ahead of the LSE's RA load forecast submissions, confirm the earliest possible effective date for the community choice aggregator (CCA) expansion by letter from the Executive Director, and inform the California Energy Commission of any adjustments to the load forecast necessary due to non-compliance. Energy Division is authorized to make this determination regardless of any pending citation appeal.

12. The central procurement entity (CPE) shall report the following in both: (a) the mid-August compliance filing and (b) the September Annual Compliance Report:

Monthly Procurement Summary Covering All CPE Procurement					
Total California Public Utility Commission (CPUC) Local Allocation (excluding demand response (DR))	Total CPUC-allocated Local DR	Local Cost Allocation Mechanism (CAM) (non-DR)	Total Procured Resources	Total Self-Shown	Net Total

(a) Total aggregate monthly megawatt (MW) amount of procurement not offered to the CPE in deficient areas;

(b) Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and

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(c) Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

13. The confidentiality matrix adopted in Decision 22-03-034 is modified to add the following categories.

Competitive Solicitation Information	Individual/ Specific Bid/Offer data	Confidential	3 years after conclusion of solicitation	Disclosure of the bid/offer data received during CPE procurement could potentially have an adverse effect on the market, put the CPE at a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured.
Competitive Solicitation Information	Aggregate Bid/Offer Data Not Selected/Procured (where the total exceeds 10 MWs)	Public	N/A	N/A

A modified version of the confidentiality matrix adopted in Decision 22-03-034 is attached as Appendix A.

14. A load-serving entity (LSE) that has self-shown a local Resource Adequacy (RA) resource to the central procurement entity is permitted to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system

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and/or flexible RA needs, as required by Ordering Paragraph 2 of Decision 22-02-034.

15. For any load-serving entity (LSE) that has self-shown a local resource to the central procurement entity (CPE), and subsequently sells the capacity to another LSE, the selling LSE shall modify its attestation to the CPE to provide that:

(1) The LSE has sold the capacity to another LSE, and the purchasing LSE will self-show the Resource Adequacy (RA) resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs as required by Ordering Paragraph 2 of Decision (D.) 22-02-034; and
(2) If applicable, the resource that the LSE intends to self-show for compensation under the Local Capacity Requirement Reduction Compensation Mechanism meets the eligibility requirements pursuant to D.20-12-006.

The modified attestation shall be provided to the CPE within 30 days of the purchase. The purchasing LSE shall provide an attestation to the CPE that it intends to self-show the capacity within 30 days of the purchase.

16. If a load-serving entity (LSE) procures available transmission capability (ATC), or acquires ATC through the resale process, at either the California-Oregon Border/Malin or the Nevada-Oregon Border, the LSE is permitted to pair the ATC with Resource Adequacy (RA) imports to meet its RA requirements.

17. Penalty points accrued by a load-serving entity (LSE) will be applied to an LSE's month-ahead and/or year-ahead Resource Adequacy (RA) penalties. If an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the

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LSE enters the higher tier. The month in which an LSE accrues points that brings the LSE into the next tier, the higher penalty will apply to the deficient month for which the points were accrued. The requirements adopted here are effective beginning for the July 2023 RA filing.

18. All year-ahead Resource Adequacy (RA) deficiencies will be charged at the Tier 1 price, and in the month-ahead RA process, the load-serving entity (LSE) will pay the difference between its month-ahead tier penalty and the Tier 1 penalty that was already paid on its year-ahead RA deficiency, plus the LSE's current tier price on any incremental month-ahead RA deficiency. The following formula will be applied:

- Year-Ahead penalty = $\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier 1 Price}$
- Month-Ahead penalty = $[(\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier Price}^{\text{Month-Ahead}}) - \text{Year-Ahead penalty}] + (\text{Deficiency}_{\text{Month-Ahead incremental}} \times \text{Tier Price}^{\text{Month-Ahead}})$

19. For any load-serving entities' (LSE) month-ahead and year-ahead Resource Adequacy (RA) deficiencies, the following information is deemed not confidential and will be published on the Commission's website by the Consumer Protection and Enforcement Division (CPED) or Energy Division: the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued. The information will be published no earlier than October 1 of the compliance year. For other non-deficiency RA program violations, such as late load forecasts and late RA filings, the information on the RA citation is deemed not confidential and may be published on the Commission's website by CPED or Energy Division.

20. A local Resource Adequacy waiver request that is filed past the submission deadline will be rejected.

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21. For the 1st quarter of each year, Energy Division will provide Cost Allocation Mechanism (CAM) and Reliability Must Run (RMR) credits to load-serving entities (LSE) no later than five business days after the California Independent System Operator (CAISO) provides the California Public Utilities Commission (CPUC)-jurisdictional RMR credits to Energy Division.

22. A load-serving entity (LSE) is permitted one load migration update in mid-February to cover May to December load migration. Other than the one load migration update, an LSE's load forecast is locked in for the January-April timeframe and the May-December timeframe of each Resource Adequacy compliance year.

23. Energy Division is authorized to lead a working group, with support from California Energy Commission (CEC) Staff, to refine elements of the CEC's incentive-based supply-side demand response qualifying capacity proposal and submit a joint proposal in the Resource Adequacy (RA) proceeding in December 2024. The schedule for the Working Group and the joint report is as follows:

Milestone	Timeframe
Initiate Working Group to refine specific elements of the CEC proposal, as directed by Commission Decision.	July 2023
LIP process begins for 2025 RA compliance year. In ex post analysis on 2023 performance, the CEC methodology is run side-by-side by LIPs on a "what if" basis with no penalties applied.	December 2023
Final LIP reports for 2025 RA compliance year filed. Energy Division and CEC draft joint report summarizing ex post results for 2023.	April 2024
Energy Division and CEC continue refining incentive-based proposal, incorporating learnings from "what if" exercise.	April - December 2024

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Energy Division and CEC submit refined incentive-based proposal to RA proceeding.	December 2024
LIP process begins for 2026 RA compliance year.	December 2024

24. Beginning with the 2024 Resource Adequacy compliance year, in order for proxy demand response resources to count toward Resource Adequacy requirements, proxy demand response resource bids must not exceed $949 per megawatt hour in either the day-ahead or real-time market. The Energy Division Director or their delegate is authorized to issue correction or deficiency notices to load-serving entities if any non-compliant proxy demand response resources are shown on their Supply Plans and the load-serving entities do not have enough capacity to meet their Resource Adequacy requirements without the non-compliant proxy demand response resources. This requirement does not apply to demand response auction mechanism resources contracted for the 2024 delivery year.

25. To the extent tariff adjustments are needed to operationalize the reliability demand response resource dispatch trigger, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

26. Beginning with the 2024 Resource Adequacy compliance year, the Prohibited Resources policy, as defined in Decision 16-09-056 and subsequent decisions and resolutions, applies to all Resource Adequacy-eligible demand response resources.

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27. Beginning with the 2024 Resource Adequacy compliance year, the Prohibited Resources Verification Plan applies to all Resource Adequacy-eligible demand response resources.

28. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are authorized to recover costs associated with implementing the Prohibited Resources requirements adopted in Ordering Paragraphs 26 and 27 through the cost recovery mechanisms authorized under the existing Prohibited Resources policy or through another mechanism if adopted through Application 22-05-002 et al. or a subsequent five-year demand response program and budget application.

29. The Transmission Loss Factor adder and the Planning Reserve Margin adder for demand response resources are removed beginning with the 2024 Resource Adequacy compliance year and for the 2024 slice-of-day test year.

30. Beginning with the 2024 Resource Adequacy compliance year, all demand response resources, except Reliability Demand Response Resources, are required to be available during all days during which a California Independent System Operator (CAISO) Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, Alert, or Notice, or the Governor's Office has issued an emergency notice. The resource must be available for the duration of an Alert, Warning, or Notice that is issued prior and up to the 10 a.m. day-ahead market bid deadline. Load-serving entities are required to implement these requirements in contracts with demand response providers.

31. Demand Response Net Qualifying Capacity filings are required to be made the first business day of the month two months prior to the requested month. Failure to meet the deadline requirement will disqualify a demand response provider's month-ahead supply plan request.

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32. Beginning with the capacity awards granted through the LIP process for the 2024 Resource Adequacy compliance year, test performance failures will be considered when making capacity awards to non-investor-owned utility demand response (DR) resources procured by third-party DR providers under the Load Impact Protocols (LIPs). Derates will be applied so that they correspond to performance during test events for the most recently available quarterly test results at the time of the award for the relevant quarter. The average performance results of each quarter will inform the capacity awarded through the LIPs for the respective sub-load aggregation point.

33. In addition to the service list in this proceeding, the proposed decision was served on the service list for Rulemaking 20-11-003, the Order Instituting Rulemaking to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.

34. The requirements adopted in this decision are effective immediately, unless stated otherwise.

35. Rulemaking 21-10-002 is closed.

This order is effective today.

Dated June 29, 2023, at San Francisco, California.

ALICE REYNOLDS
President
GENEVIEVE SHIROMA
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
Commissioners

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APPENDIX A

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EXHIBIT 5

California Community Choice Association's Application for Rehearing of Decision 23-06-029

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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.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S APPLICATION FOR REHEARING OF DECISION 23-06-029

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July 26, 2023

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SPECIFICATION OF ERROR

California Community Choice Association hereby requests rehearing of Decision (D.) 23-06-029 (Decision) and the California Public Utilities Commission's (Commission's) prohibition of the expansion of a community choice aggregator's (CCA's) service area if the CCA had a Resource Adequacy (RA) deficient in the prior two calendar years. Rehearing should be granted based on the following legal errors set forth in the Decision:

- The Commission exceeds its jurisdiction, and therefore fails to act in the manner required by law, by acting outside of its express, narrow, and predominantly administrative authority under Public Utilities Code Section 366.2 over CCA implementation plans, and by impairing the express statutory right of customers to aggregate their loads with a CCA.

- The Commission unlawfully justifies its jurisdictional reach and impliedly exerts its authority over CCA expansion by "harmonizing" its authority under Sections 366.2 (CCA implementation), 365.1 (electric service provider (ESP) implementation), and 380 (RA rules and enforcement mechanisms), despite California law requiring express authorization of jurisdiction over CCAs as governmental bodies and not allowing harmonization of statutes when the authority set forth in such statutes is unambiguous. As such, the Commission exceeds it jurisdiction and fails to act in the manner required by law.

- The Commission misapplies and exceeds its statutory authority to prevent cost shifts by failing to identify the costs and impose them on CCA customers as required by subsections 366.2(c)(5) and 366.2(c)(7), and failing to read the more general cost shift language of Section 366.2(a)(4) in light of the requirements of Section 366.2(d), (e), and (f) regarding prevention of cost shifts in connection with CCA implementation. As such, the Commission exceeds its jurisdiction and fails to act in the manner required by law.

- The Commission overreaches in its authority to provide an "earliest possible date" for CCA expansion under Section 366.2(c)(8) by applying a requirement outside of the express statutory requirement that the Commission only consider the impact of the expansion on the investor-owned utility's (IOU's) annual procurement plan. Instead, the Commission has inserted as a factor determining the "earliest possible date" the evaluation of a CCA's RA compliance history. The Commission has thus exceeded its jurisdiction and failed to act in the manner required by law.

- The Commission violates Section 380 requiring the Commission to enforce its RA program rules in a nondiscriminatory manner by applying the rule against expansion as an additional RA enforcement policy imposed on CCAs and ESPs, but not on IOUs. The Commission violates Section 380's requirement for nondiscriminatory enforcement despite the availability of less restrictive, and nondiscriminatory, measures in Section 380 including improving the existing RA penalty structure or allocating the costs of generating capacity and demand response in a manner that prevents cost shifts. As a result, the Commission exceeds its jurisdiction and fails to act in a manner required by law.

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- The Commission abuses its discretion by basing its Decision to restrict CCA expansions on conclusory, superficial, unsupported, and largely incorrect findings. As a result, the Commission has failed to act in the manner required by law.

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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.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S APPLICATION FOR REHEARING OF DECISION 23-06-029

Pursuant to Rule 16.1 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure, Section 8.1 of General Order 96-B, and California Public Utilities Code Section 1731,[1] California Community Choice Association[2] (CalCCA) submits this Application for Rehearing of Decision (D.) 23-06-029[3] (Decision) issued in Rulemaking (R.) 21-10-002 on July 5, 2023. The Decision, among other things, prohibits the expansion of a community choice aggregator's (CCA's) service area if the CCA had a Resource Adequacy (RA) deficiency in the prior two calendar years. This application for rehearing is timely filed.

[1] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay 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.

[3] D.23-06-029, *Decision Adopting Local Capacity Obligations For 2024 - 2026, Flexible Capacity Obligations for 2024, and Program Refinements*, R.21-10-002 (July 5, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

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I. INTRODUCTION

California Public Utilities Code Section 366.2(a) expressly entitles customers "to aggregate their electric loads as members of their local community with community choice aggregators."[4] The Commission's jurisdiction in this process is narrowly limited and primarily administrative, derived solely from the Legislature's express grants of authority over CCAs. Unlike its regulation of public utilities, the Commission has no general jurisdiction to regulate CCAs or the customers or local governments that form the CCAs.

The Decision exceeds the Commission's jurisdiction, and results in the Commission not proceeding in the manner required by law, by impairing this express right of customers to aggregate their electric loads with a CCA. Specifically, the Decision unlawfully prohibits customers from aggregating load with an existing CCA if the CCA has a history of noncompliance with the Commission's regulations governing resource adequacy (RA), promulgated under Section 380, in the prior two years (New Rule).[5]

The Commission may not, as it has done in the Decision, lawfully expand its jurisdiction to promulgate the New Rule by simply "harmonizing" statutes addressing separate subjects, particularly when there is no conflict among the statutes. And while courts may defer to the Commission's judgment in some circumstances, the Commission is not entitled to deference in its interpretation of statutes delimiting its jurisdiction.

The Commission also fails to comply with the requirement in Section 380 that it apply its RA enforcement authority in a nondiscriminatory manner to CCAs. The Commission has a range

[4] Assembly Bill No. 117, Chapter 838 (2002) (An act to amend Sections 218.3, 366, 394, and 394.25 of, and to add Sections 331.1, 366.2, and 381.1 to, the Public Utilities Code, relating to public utilities) (AB 117).

[5] Throughout this Application for Rehearing, CalCCA refers both to the customer right to aggregate load through forming a CCA and joining an existing CCA (i.e., a CCA expansion) as CCA implementation, as both require the same Implementation Plan to be filed pursuant to Section 366.2.

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of even-handed measures that can be used to address RA noncompliance without exceeding its jurisdiction over CCAs or applying enforcement mechanisms to CCAs or Electric Service Providers (ESPs) without applying the same mechanisms to investor-owned utilities (IOUs). By failing to adopt such nondiscriminatory measures, the Commission acts outside of its jurisdiction and fails to proceed in a manner required by law.

Finally, the Commission abuses its discretion and therefore fails to act in the manner required by law by making findings without explanation or support in the record. The Commission has not explained and cannot support its findings that CCA RA noncompliance is "subsidized" by other customers and affects grid reliability. Other customers do not contribute to the cost of replacement RA to account for a CCA's noncompliance, and the Commission has not asserted that such replacement purchases are made. The regulatory framework requires replacement RA resources needed to bolster reliability to be procured, instead, by the California Independent System Operator (CAISO) under Federal Energy Regulatory Commission (FERC) authority, and the costs are billed directly to the noncompliant CCA or other load-serving entity (LSE).

CalCCA requests rehearing of D.23-06-029 to correct these legal errors.

II. THE DECISION VIOLATES CUSTOMERS' STATUTORY RIGHT TO AGGREGATE THEIR ELECTRIC LOADS WITH A CCA

The Decision treads directly on the rights granted to customers by the Legislature in AB 117, set forth in Section 366.2: "[c]ustomers shall be entitled to aggregate their electric loads as members of their local community with [CCAs].[6] A local community's election to implement or expand a CCA program is accomplished through local ordinance.[7] AB 117 requires the Commission to

[6] § 366.2(a)(1).
[7] § 366.2(c)(12).

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perform distinct, administrative, and narrowly designated tasks related to CCA implementation after a public agency's adoption of a CCA implementation plan at a duly noticed public hearing:

- Development of a cost-recovery mechanism to be imposed on a CCA pursuant to subsections [366.2] (d), (e), and (f) to be paid by the customers of the CCA to prevent shifting of costs from the CCA's implementation;[8]

- Notification to the IOU serving the customers proposed for aggregation that a CCA implementation plan has been filed (within ten days of filing);[9]

- Certification that the Commission has received the implementation plan (and any other information requested by the Commission to determine a cost-recovery mechanism) (within 90 days of filing);[10]

- Provision of findings to the CCA regarding cost recovery that must be paid by the CCA's customers to prevent cost shifting as provided for in [Section 366.2] (d), (e), and (f),[11] and authorization of implementation only if the cost recovery mechanism is imposed;[12] and

- Designation of the "earliest possible effective date" for CCA implementation, "taking into consideration the impact on" the IOU's Commission approved annual procurement plan.[13]

The Decision unlawfully expands the Commission's authority related to CCA implementation and expansion beyond that set forth in Section 366.2 by, among other things:

- Establishing the New Rule "harmoniz[ing] the statutory scheme as a whole, including Sections 380 [RA enforcement], 365.1 [direct access transactions] and 366.2";[14]

- Applying the New Rule to CCA implementation plans submitted after the effective date of the Decision,[15] beginning with the September 2023 month-ahead filing and the 2024 year-ahead RA filing due October 21, 2023;[16]

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8 § 366.2(c)(5).
9 § 366.2(c)(6).
10 § 366.2(c)(7).
11 *Ibid.*
12 § 366.2(i).
13 § 366.2(c)(8).
14 Decision, Ordering Paragraph (OP) 9 at 137.
15 *Ibid.*
16 *Id.*, OP 9 at 137.

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- Applying a similar rule to ESPs but exempting the IOUs based on their current role as the Provider of Last Resort (POLR).[17]

- Excluding from the events triggering the Commission's expansion prohibition the following circumstances: (i) a year-ahead deficiency cured in the month-ahead filing, but only for year-ahead deficiencies accrued two years before the year in which the LSE files its binding load forecast;[18] (ii) a month-ahead or year-ahead system RA deficiency that is less than one percent of the LSE's system RA requirements;[19] and (iii) non-substantive "specific violations," as adopted in Resolutions E-4107 and E-4195 and modified in Decision 11-06-022.[20]

- Authorizing Energy Division to review RA referrals and citations issued by the Consumer Protection and Enforcement Division for the prior two years to determine if a CCA is eligible to expand.[21]

Neither Section 366.2 nor any other statute expressly authorize the Commission to impose the New Rule. Implicitly aware of this shortcoming, the Decision engages in hand-waving, claiming: "our approach harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2."[22]

Rehearing of the Decision and its adoption of the New Rule should be granted to address the significant legal errors set forth therein. In the sections below, CalCCA addresses the following.

- Section III discusses relevant legal authority on the scope of Commission jurisdiction and each of the purportedly "harmonized" statutes, noting, *inter alia*, that the authority permitting the Commission to regulate the acts of a public body

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17 *Ibid.*

18 *Id.* at 40, OP 10 at 138. Year-ahead deficiencies in the year that the LSE files its binding load forecast with additional load it intends to serve are not eligible for exclusion from the expansion prohibition. *Ibid*. The Commission states that there will be insufficient time for the LSE to cure the year-ahead deficiency in that year's month-ahead timeframe as the LSE will have already filed its binding load forecast commitments. *Ibid*.

19 Note that OP 10 describes a "month-ahead or system-ahead system RA deficiency," however CalCCA believes the Commission means "year-ahead system RA deficiency." *See id.* Clarification on OP 10 is therefore necessary. *Ibid*.

20 *Ibid.*; *see* D.11-06-022, *Decision Adopting Local Procurement Obligations for 2012 and Further Refining the Resource Adequacy Program*, R.09-10-032 (June 23, 2011): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/138375.PDF.

21 *Id.*, OP 11 at 138-139.

22 *Id.* at 115 (emphasis added).

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must be "express," and not simply inferred.[23] Section III also discusses California law refuting the ability to "harmonize" distinct statutes to obtain a result other than what is expressly provided in a statute. Section III also emphasizes that the usual deference provided by courts to the Commission's interpretation of its governing statutes does not extend to the Commission's interpretation of its own jurisdiction.

- Section IV examines the law set forth in Section III in the context of the Decision, describing the legal errors committed by the Commission.

- Section V. describes the failure of the Commission to act within its jurisdiction granted through Section 380 to apply the RA enforcement mechanism in a nondiscriminatory manner.

- Section VI describes the Commission's abuse of discretion resulting from the lack of evidence or analysis supporting its conclusions in the Decision.

III. RELEVANT LEGAL AUTHORITY ON COMMISSION JURISDICTION

A. The Commission's Jurisdiction Derives from Authority Expressly Granted by the Legislature

Except as expressly authorized or directed by the Legislature, the Commission has no jurisdiction over the actions of local government bodies such as CCAs, which form either as a municipality or a joint powers authority. In this regard, its jurisdiction differs greatly from its general authority over IOUs. The following describes the parameters of Commission jurisdiction over IOUs versus other entities.

The Commission's overall authority stems from the California Constitution,[24] which grants the Commission broad authority to regulate transportation companies[25] and vests the Legislature with control over privately owned providers of energy, water and telecommunications.[26] The Constitution provides that "the Legislature has plenary power . . . to

23 *Santa Clara Valley Transp. Auth. v. Pub. Utils. Comm'n* (2004) 124 Cal.App.4th 346, 364.
24 *San Diego Gas & Elec. Co. v. Super. Ct.* (1996) 13 Cal.4th 893, 914; Cal. Const., Art. XII, §§ 1-6.
25 Cal. Const., Art. XII, § 4.
26 *Id.*, Art. XII, § 3.

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confer additional authority and jurisdiction upon the [C]ommission."[27] The Legislature exercised this plenary power by enacting the Public Utilities Code, vesting the Commission with broad authority to "supervise and regulate every public utility in the State"[28] and to "do all things, whether specifically designated in [the Public Utilities Code] or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction."[29] While the Commission's authority over public utilities (i.e., IOUs) is broad, courts have even placed limits on this authority, including finding that the Commission is not authorized to disregard express legislative directives or restrictions upon its powers found in other statutes.[30]

1. The Commission Has No Jurisdiction Over the Actions of Local Government Bodies Such as CCAs Except as Expressly Authorized by the Legislature

Established law provides that except as authorized or directed by the Legislature, the Commission has no jurisdiction over the actions of government bodies such as CCAs.[31] Any authority granted by the Legislature, however, must be "express" and not simply inferred. In other words, the Commission should not presume the Legislature intended "to legislate by

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27 *Id.,* Art. XII, § 5.

28 *San Diego Gas & Electric,* 13 Cal.4th at 915; *see also* Section 701.

29 Section 701; *see also* Section 451 (Commission authority to ensure public utilities operate safely); *see also* Section 702 (public utilities must obey and comply with all Commission orders as to any matter affecting its business as a public utility).

30 *See Assemb. v. Pub. Utils. Comm'n* (1995) 12 Cal.4th 87, 103 (finding that an express legislative directive in Public Utilities Code Section 453.5 that a ratepayer refund be paid to the ratepayers of public utilities prevented the Commission from diverting that refund for other public purposes); *see also Pac. Tel. & Tel. Co. v. Pub. Util. Comm'n* (1965) 62 Cal.2d 634, 653 (Section 701 inapplicable because the actions of the Commission disregarded "express legislative directives").

31 *See Monterey Peninsula Water Mgmt. Dist. v. California Pub. Utils. Comm'n* (2016) 62 Cal.4th 693, 698 (2016) ("Public Utilities Commission … has no authority, however, to regulate public agencies like the District, absent a statute expressly authorizing such regulation…"); *see also County of Inyo v. Pub. Utils. Comm'n* (1980) 26 Cal.3d 154, 166-167 (citing *Los Angeles Metro. Transit Auth. v. Pub. Utils. Comm'n* (1959) 52 Cal.2d 655, 661 ("In the absence of legislation otherwise providing, the commission's jurisdiction to regulate public utilities extends only to the regulation of privately owned utilities").

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implication"[32] – the modern rule of construction disfavors such practice.[33] In fact, even where the activity of a government body has some relationship to an activity of a Commission-regulated utility, the Commission lacks jurisdiction over the government body's activity in the absence of express legislative authority for the Commission action at issue.[34] For this reason, the California Supreme Court held in *Monterey* that the Commission lacked jurisdiction to review a user fee imposed by a government body even though the user fee itself was billed and collected, on behalf of the government body, by a Commission-regulated utility.[35] Therefore, without express Legislative authority, the Commission lacks jurisdiction to delay customers' exercise of their rights "to aggregate their electric loads as members of their local community with community choice aggregators" under Section 366.2(a)(1).

2. The Commission Justifies Its Decision by "Harmonizing" Its Statutory Authority in Sections 366.2, 365.1, and 380

While the Commission lacks express authority to justify its New Rule, it reasons that the Decision is justified because it "harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2."[36] These sections, however, serve unique, separate, and nonconflicting purposes and do not separately or together provide the jurisdiction that the Commission claims: (i) Section 380 authorizes the Commission to oversee a CCA's RA activities; (ii) Section 365.1 governs direct access – not CCA – transactions and authorizes the Commission to recover costs from bundled and unbundled (including direct access and CCA) customers for Commission

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32 *People v. Welch* (1971) 20 Cal.App.3d 997, 1002 (citing *First M.E. Church v. Los Angeles Co.* (1928) 204 Cal. 201, 204.

33 *See Educ. & Recreational Servs., Inc. v. Pasadena Unified Sch. Dist.* (1977) 65 Cal.App.3d 775, 782 (rejecting an argument that the Legislature implied meaning in a statute); *see also San Diego Serv. Auth. for Freeway Emergencies v. Super. Ct.* (1988) 198 Cal.App.3d 1466, 1472 ("a Court should not presume the Legislature intended to legislate by implication") (citing *People v. Welch* (1971) 20 Cal.App.3d at 1002).

34 *See Monterey,* 62 Cal.4th at 699-700.

35 *Ibid*.

36 Decision at 115.

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authorized or ordered central procurement of RA by an IOU; and (iii) Section 366.2 governs implementation of a new or expanded CCA. Each separate and distinct area of statutory authority is described below.

a. Section 366.2 Establishes a Detailed, Narrow Scope of Commission Jurisdiction Over CCA Implementation and Expansion

As discussed in Section II above, the Commission's authority in connection with CCA implementation is expressly set forth in Section 366.2. The statute prescribes the rights and obligations of customers aggregating their load through a CCA, the responsibilities of the CCA, and the Commission's, narrow, distinct, and largely administrative roles in the implementation process to:

- "[N]otify any electrical corporation serving the customers for aggregation that an implementation plan initiating [CCA] has been filed" (within 10 days of implementation plan filing);[37]
- Seek "information …. that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f)";[38]
- "Certify" that it "has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism" (within 90 days of implementation plan filing);[39]
- Provide the CCA with findings regarding any cost recovery to be paid by customers of the CCA to prevent cost shifting as provided for in Sections 366.2 (d), (e), and (f)[40] and authorize implementation only if the cost recovery mechanism is imposed;[41]
- "[D]esignate the earliest possible effective date for implementation" of the CCA program "taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission";[42] and

37 § 366.2(c)(6).
38 § 366.2(c)(5).
39 § 366.2(c)(7).
40 *Ibid.*
41 § 366.2(i).
42 § 366.2(c)(8).

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- Oversee electrical corporation cooperation in the implementation of the CCA program.[43]

The New Rule, effectively extending the Commission's jurisdiction over CCA implementation, is not expressly provided for in Section 366.2, or in any other statute.

The Decision's expansion of jurisdiction conflicts with the Commission's prior express and clear acknowledgement of the limits of its jurisdiction over CCAs. In its first major decision on implementation, the Commission concluded that AB 117 does not confer authority for "general regulatory oversight of CCAs"[44] and further clarified its belief that nothing in "AB 117 intended to give this Commission broad jurisdiction over CCAs."[45] In focusing specifically on the regulatory process for considering CCA implementation, it found that: "AB 117 does not provide us with authority to approve or reject a CCA's implementation plan or to decertify a CCA."[46] Importantly, it also concluded that its jurisdiction was limited by the express terms of the statute: "We assume that if the Legislature intended for us to regulate the CCA's implementation plan in other ways, the Legislature would have included explicit language in the statute with regard to its intent."[47]

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[43] § 366.2(c)(9).

[44] D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters,* R.03-10-003 (Dec. 15, 2005), Conclusion of Law (COL) 2, at 60; *see also id.* COL 1, at 60 and Finding of Fact (FOF) 2, at 56: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/52127.PDF.

[45] *Id.* at 16; *see also* D.12-09-021, *Order Denying Rehearing of Resolution E-4250*, Application 10-05-015 (Sept. 13, 2012) (the Commission acknowledges its "limited jurisdiction over CCAs" in contrast to its "general jurisdiction" over IOUs).

[46] D.05-12-041, at 4; *see also id.,* at 14 ("we find nothing in the statute that directs the Commission to approve or disapprove an implementation plan or modifications to it. Nor does the statute provide explicit authority to 'decertify' a CCA or its implementation plan").

[47] *Id.* at 15. The Commission seems to suggest that D.05-12-041 claimed authority to terminate a CCA's service. *See* Decision at 37. The quoted language omits key elements of the relevant finding of fact in D.05-12-041 and the underlying discussion. The Commission contemplated termination "in the event of a system emergency or where public health or safety is involved" and then only after an order by the Commission. *See* D.05-12-041 at 49. Moreover, the Commission has never terminated a CCA service for any reason and thus the scope of its authority has not been tested by a court.

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As discussed further in Section IV.C, the New Rule, by interpreting the Commission's "overall" and "harmonized" authority in Sections 365.1, 366.2 and 380, ignores this previous acknowledgment of the Commission's narrowly established authority over CCA implementation.

b. Section 380 Establishes the Scope of Commission Jurisdiction Over CCAs' Resource Adequacy Activities

As discussed above, the Decision claims to have "harmonized" Section 366.2 with Section 380 to justify the New Rule for CCAs.[48] Section 380, granting authority to the Commission to establish RA requirements for all LSEs (including CCAs), neither addresses nor provides any authority to the Commission over CCA implementation plans. Instead, this statute represents an entirely separate authority addressing oversight of RA once a CCA is operational.

The Commission has developed its RA program over nearly two decades; its first key decision framed the program in 2004[49] with requirements very similar to those of the current program. Not until the adoption of AB 380 (Nunez, 2005), however, did the Legislature expressly grant the Commission authority to oversee the RA activities of CCAs. Section 380 provides the Commission authority to establish an RA program to ensure the reliability of electric service in California, which applies equally to all LSEs, including IOUs, CCAs, and ESPs.[50] Although Section 366.2 was enacted in 2002, AB 380 (enacted in 2005) did not alter or cross-reference Section 366.2.

Section 380 does not provide authority for the Commission to tie a CCA's RA compliance history to its implementation. However, Section 380 expressly contains four

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[48] Decision at 115.

[49] D.04-01-050, *Interim Opinion*, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development, R.01-10-024 (Jan. 22, 2004), at 10-17: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/33625.PDF.

[50] § 380 applies to "load serving entities" as defined in subdivision (k).

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important directives relevant to the reliability issues that the Commission purports to address in the Decision. First, it expressly gives the Commission a tool to prevent cost shifting among customers, requiring the Commission to "[e]quitably allocate the cost of generating capacity and demand response in a manner that prevents the shifting of costs between customer classes."[51] Second, it authorizes the Commission to ensure compliance with its RA program through the exercise of its enforcement powers.[52] Third, it must exercise its powers in a way that "[m]inimize[s] enforcement requirements and costs" and in a "nondiscriminatory manner."[53] Fourth, it requires the Commission to determine "the most efficient and equitable means" for achieving the goals set forth in Section 380.[54] Importantly, nothing in Section 380 expressly establishes a new enforcement power related to CCA implementation plans or permits the Commission to tie its RA enforcement authority to any distinct authority the Commission holds in another statute such as Section 366.2.

c. Section 365.1 Among Other Things, Governs Direct Access and Cost Recovery for Centralized Resource Adequacy Procurement

The Decision relies not only on Sections 366.2 and 380 but contends that these provisions have also been harmonized with a third Section, 365.1, to justify the Commission's action.[55] While the Commission summarily states that it "disagrees that …Section 365.1 constrain[s] the Commission's ability to ensure CCAs seeking to expand service of meeting their RA requirements,"[56] the Decision does not explain where in the 1,300 words of Section 365.1 it finds support for its position. CalCCA agrees that this section does not expressly "constrain" the

51 § 380(b)(3) (original Section 380(b)(2)).
52 § 380(e).
53 *Id*.
54 § 380(h).
55 Decision at 115.
56 *Ibid*.

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Commission's action but neither does it expressly authorize or justify its New Rule. On its face, the section seems irrelevant to the question at hand given that it predominantly governs direct access.

In fact, only subdivisions (c) and (d) of Section 365.1 apply to CCAs; the other sections apply to "other providers" (such as ESPs) which expressly excludes CCAs.[57] The two applicable subdivisions prescribe the cost recovery mechanism to address circumstances in which the Commission orders an IOU pursuant to Section 380 to centrally procure RA generation resources for the benefit of all customers. Neither subdivision expressly authorizes the Commission to do so by rejecting an expansion plan of a CCA. It is unclear how the Commission "harmonized" this statute with other statutes to support its New Rule.

B. The Commission's Construction of Statutes Delimiting Its Jurisdiction is Not Entitled to Deference by Courts

Because the Commission may only take actions with respect to government bodies that are expressly authorized by the Legislature, whether the Commission has exceeded its jurisdiction will often turn on the construction of a statute purportedly providing that express authority. Unlike the deference granted by courts to the Commission's interpretation of statutes subject to the regulatory jurisdiction of the Commission, its construction of the scope of its authority under such statutes is entitled to no deference by a reviewing court.[58] Instead, construction of the statute at issue is subject to independent review.[59]

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57 § 365.1(a).

58 *See Santa Clara Valley,* 124 Cal.App.4th at 359 ("This case turns on statutory interpretation and issues of legislative intent underlying sections 1201 and 1202 as well as the VTA's enabling legislation and related statutes applicable to public light rail transit systems. … Therefore, our review is independent review"); *see also PG&E Corp. v. Pub. Utils. Comm'n* (2004) 118 Cal.App.4th 1174, 1194-95 ("the general rule of deference to interpretations of statutes subject to the regulatory jurisdiction of agencies does not apply when the issue is the scope of the agency's jurisdiction…(Citations omitted)…..We conclude that the PUC's interpretation of the scope of its own jurisdiction must bear more than just a "reasonable relation" to statutory purposes and language…").

59 *See Santa Clara Valley,* 124 Cal.App.4th at 359; *see also PG&E Corp.,* 118 Cal.App.4th at 1194-95.

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Here, the Commission contends that its jurisdiction to delay or prevent CCA expansion turns on the harmonization of three statutes: Sections 366.2, Section 380, and Section 365.1.[60] As discussed above, none of these statutes independently provides the requisite authority to reject or delay the rights of local communities to adopt community choice, whether through a new or expanded CCA. Section 366.2 establishes in great detail the narrow scope of the Commission's role in reviewing a CCA's implementation plan. Section 380 separately prescribes the scope of the Commission's jurisdiction over CCAs in regulating their RA activities. Section 365.1 primarily applies to direct access and ESPs; subdivisions (c) and (d), however, address cost recovery for all customers for any centralized resource adequacy procurement the Commission directs. None of these statutes expressly authorizes the Commission to delay or prevent expansion of CCA service. In the event of court review of the Decision, the Commission's novel "harmonization" of the three statutes to grab authority not otherwise expressly provided by statute will be subject to a Court's independent review.

IV. THE DECISION EXCEEDS THE COMMISSION'S JURISDICTION BY PROHIBITING CUSTOMERS FROM AGGREGATING THEIR LOADS WITH AN EXISTING CCA BASED ON THE CCA'S PRIOR RA COMPLIANCE HISTORY

A. The Legislature Has Not Expressly Authorized the Commission's Action

The Commission has exceeded its limited jurisdiction over CCAs by conditioning a local community's aggregation of customer loads with an existing CCA on the existing CCA's RA compliance history. As explained in Section III.A.1, the Commission has no general authority over local governments absent express statutory authority. Moreover, nothing in the three statutes cited by the Decision – Sections 366.2, 365.1, or 380 expressly authorizes the Commission to take this action; indeed, the Decision claims no express authority. In adopting the New Rule to prohibit

[60] Decision at 115.

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customers from aggregating their loads with an existing CCA based on the CCA's prior RA compliance history, the Decision therefore exceeds the Commission's jurisdiction.

The Commission must look to the plain language of Section 366.2, which clearly and in great detail delineates the role of the Commission in CCA implementation. Nothing in that language permits the Commission to prevent or delay implementation of an expansion based on the existing CCA's RA compliance history.

B. The Decision Exceeds the Commission's Statutory Jurisdiction to Prevent Cost Shifts

The Decision appears to suggest that its New Rule has been adopted to prevent cost shifting among customer classes. Finding of Fact 6 states: "LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting."[61] It further observes its duty to prevent cost shifting in Section 366.2(a)(4) and to allocate costs equitably under Section 380.[62] While the Legislature has delegated these responsibilities to the Commission, the Commission misapplies and exceeds its authority.

As an initial matter, the misapplication of its authority is unmistakable in its choice of remedies to address the purported cost shift. Preventing cost shifts for CCA implementation, as Section 366.2(c)(5) describes, is achieved by identifying the costs that "shall be paid by the customers of the community choice aggregator." The Commission has historically identified such costs in its Power Charge Indifference Adjustment (PCIA) proceeding, R.17-06-026,[63] and the proceeding's predecessors. The Commission calculates these costs annually in each IOU's

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61 Decision at 130.

62 *Id.* at 36.

63 *See generally, e.g.,* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K687/232687030.PDF.

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Energy Resource Recovery Account (ERRA) proceeding,[64] and imposes the costs as a nonbypassable charge on each customer's bill. If the Commission believes, as it suggests in the Decision, that a cost shift was occurring, its statutory authority requires it to identify the cost and impose it on CCA customers, not to prevent or delay a CCA's expansion.

Likewise, the Commission has equitably allocated reliability costs under Section 380 for many years, using its Cost Allocation Mechanism, both on a collective[65] and individual LSE[66] basis. Nothing in the Decision, however, suggests that there is a need for reallocation of any reliability costs. In short, if the problem was purported cost shifting, the Commission failed to deploy the remedy the Legislature provided: allocation of centrally procured RA costs.

In addition, the types of costs the Commission has identified as a potential "cost shift" fall outside the bounds of its authority under Section 366.2(c)(7). This section defines the scope of cost shifts the Commission is authorized to address in CCA implementation, pointing to subdivisions (d), (e), and (f). These costs currently are addressed in the Commission's PCIA proceeding, R.17-06-026. The Decision goes beyond these categories and institutes new and statutorily undelineated cost shift policy based upon RA deficiencies.

Specifically, Section 366.2 permits recovery of several categories of costs as defined in subdivisions (d), (e), and (f). Subdivisions (d) and (e) require recovery from CCA customers of

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64 *See, e.g.,* D.22-12-044, *Decision Adopting the Electric Revenue Requirements and Rates Associated with the 2023 Energy Resource Recovery Account and Generation Non-bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation and the 2023 Electric Sales Forecast for Pacific Gas and Electric Company*, A.22-05-029 (Dec. 15, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043722.PDF.

65 D.06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, R.06-02-013 (July 20, 2006): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58268.PDF.

66 D.22-05-015, *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations*, R.20-05-003 (May 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M479/K339/479339449.PDF.

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Department of Water Resources (DWR) costs stemming from the 2000-2001 energy crisis. Subdivision (f) requires recovery of the IOU's "past undercollections" for IOU purchases prior to the load departing. The statute provides no other express categories of cost recovery in the CCA implementation process.

The types of cost shift addressed by the Decision go beyond the scope of this express authority. The Decision finds "that LSEs that are deficient in their RA obligations result in leaning on other LSEs' procurement activities."[67] The Decision asserts that "if one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability."[68] These costs do not fall within the scope of subdivisions (d), (e), or (f) and, critically, the Decision does not claim otherwise.

Finally, the more general language of Section 366.2(a)(4) must be read within the context of the overall implementation statute. Subdivision (a)(4) provides that "[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." While subsection (a)(4) provides the principle, it is informed by later subdivisions (d), (e), and (f) to provide the explicit mechanisms to prevent such cost shifting.

Fundamental rules of statutory construction require reading together the sections within a statutory provision.[69] Harmonizing the subsections of Section 366.2, the legislative intent is clear: subsections (d), (e), and (f) are the methodologies provided by the Legislature to prevent the cost

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67 Decision at 37-38.

68 *Id.* at 37.

69 *See Select Base Materials v. Bd. of Equalization* (1959) 51 Cal.2d 640, 645; *see also Moyer v. Workmen's Comp. Appeals Bd.* (1973) 10 Cal.3d 222, 230-31 (citing *Select Base Materials,* 51 Cal.2d at 645).

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shifting identified in subsection (a)(4) that may result from the implementation of the CCA program. In other words, subsection (a)(4) was not enacted in a vacuum and does not alone provide the Commission authority to prevent cost shifting outside of Section 366.2's parameters.

C. The Commission May Not Rewrite Existing Law to Imply Jurisdiction to Establish the New Rule by "Harmonizing" the Statutory Scheme as a Whole

The Commission cannot cure its lack of jurisdiction through the Decision's misapplication of a canon of statutory interpretation. Lacking express statutory authority for its action, the Decision touts its "new requirement" as falling "under the umbrella of reliability and [RA] for CCAs planning to implement an expansion."[70] The Commission rests its action on its "statutory obligations to ensure energy reliability at just and reasonable rates and specific authority to ensure RA compliance" and its theory that "harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2."[71] As an initial matter, the Decision lacks any explanation of the ambiguity or conflict the harmonization was intended to address or the rationale supporting its conclusion. Even if there were a cogent explanation, however, the Commission cannot simply rewrite existing law by tying together two limited grants of authority on separate subject matters – certification of CCA implementation and RA enforcement authority over all LSEs – to create an overarching "new" requirement for CCAs.

Harmonization, as a canon of statutory construction, is the process of reconciling conflicting statutes and interpreting them in a way that gives effect to the intent of the legislature. Statutory construction begins with the plain language of the statutes and "their respective texts."[72] In general, "[i]f two seemingly inconsistent statutes conflict, the court's role is to

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70 Decision at 37.

71 *Id.* at 115.

72 *State Dept. of Pub. Health v. Super. Ct.* (2015) 60 Cal.4th 940, 956 (citing *Pineda v. Williams–Sonoma Stores, Inc*. (2011) 51 Cal.4th 524, 529 ("we look first to the words of a statute, 'because they generally provide the most reliable indicator of legislative intent'")).

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harmonize the law."[73] As the California Supreme Court observed: "The cases in which we have harmonized potentially conflicting statutes involve choosing one plausible construction of a statute over another in order to avoid a conflict with a second statute."[74] Moreover those statutes must relate to the same subject.[75] Courts have made clear, however, that "the requirement that courts harmonize potentially inconsistent statutes when possible is not a license to redraft the statutes to strike a compromise that the Legislature did not reach."[76]

The California First District Court of Appeals addresses strikingly similar circumstances in 2022 in *Shiheiber v. JPMorgan Chase Bank, N.A.*[77] In *Shiheiber*, the cross-complainant Henderson attempted to interpret Civil Procedure Code Section 575.2, providing enforcement mechanisms for superior courts for their local rules, by reading it in the "context of its surrounding statutes" including Sections 575 and 128.5.[78] The court first finds that "[g]iven its entirely different language, subject and provenance, section 575 [governing rules adopted by the Judicial Council] simply has no bearing on the interpretation of section 575.2."[79] The Court concludes:

> [C]ontrary to Henderson's suggestion that there is something in section 575 with which section 575.2 must be "harmonized," she points to no conflict between the two sections, and we can conceive of none.[80]

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73 *Stone St. Capital, LLC v. California State Lottery Comm'n* (2008) 165 Cal.App.4th 109, 118-119 (citations omitted).

74 *State Dept. of Pub. Health,* 60 Cal.4th at 956 (citations omitted); *see also Grassi v. Super. Court* (2021) 73 Cal.App.5th 283, 307(citations omitted).

75 *See Wirth v. St. of California* (2006) 142 Cal.App.4th 131, 140 (citations omitted) (finding statutes addressing "salary and benefits" and "supervisory compensation differential" on the same matter); *see also Med. Bd. of California v. Super. Ct.* (2001) 88 Cal.App.4th 1001, 1015 (finding statutes addressing discipline action for a licensee on the same matter).

76 *St. Dept. of Pub. Health,* 60 Cal.4th at 956 (citations omitted); *see also Grassi*, 73 Cal.App.5th at 307 (citations omitted).

77 *Shiheiber v. JP Morgan Chase Bank, N.A*. (2022) 81 Cal.App.5th 688.

78 *Id.* at 699.

79 *Ibid.*

80 *Ibid*.

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Henderson also argued that Section 575.2 must only be applied under the broader rules set forth in Section 128.5, requiring a showing of bad faith for sanctions. The Court observes that "Henderson makes *no* attempt at any valid exercise in statutory interpretation" of the unambiguous meaning of Section 575.2 (which does not require the bad faith showing).[81] The Court finds that:

> . . . Henderson does not engage at all with the statutory text. She has identified no ambiguity in the statutory language that calls for judicial construction, much less has she articulated any cogent reason for us to read into the statutory language a limitation the Legislature did not state expressly.[82]

Shiheiber is highly instructive in this case given that the court refuses in two instances to "harmonize" statutes when the unambiguous meaning of such statutes is clear. In the Decision, the Commission attempts harmonization similar to Henderson, when the meaning of Sections 365.1, 366.2, and 380 are unambiguous. As in *Shiheiber,* however, no legal reason exists to "harmonize" the statutes except for the Commission attempting to justify its expansion of jurisdiction.

The Commission has done just what California courts forbid: it either has rewritten Section 366.2 to include a new criterion for certification of a CCA implementation plan or rewritten Section 380 to override the very specific CCA implementation directives in Section 366.2. In the case of the Commission's New Rule, there is no conflict or inconsistency among the statutes the Decision relies on and thus no reason to "harmonize" those statutes; the Commission cites no such conflict. Instead, the statutes simply address different subjects of regulation. Section 366.2 governs implementation or "start-up" of a CCA, while Sections 380 and 365.1 govern RA activities of an operational CCA or direct access provider.

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81 *Id.* at 701 (emphasis in original).

82 *Id.* at 702.

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There is no conflict among these provisions. Even if there *were* a conflict between Sections 366.2 and 380, it would be one of the Commission's own creation. Nothing in the language of Section 366.2 prevents the Commission from administering and enforcing the RA program governing CCAs. Indeed, the Commission has overseen and enforced the RA program under Section 380 without the New Rule, as discussed in greater detail in Section V. Similarly, nothing in the language of Section 380 prevents the Commission from administering Section 366.2 as the Legislature directed. Only when deploying the New Rule as an RA enforcement mechanism does it become a conflict. Had the Commission remained in the lanes the Legislature created, continuing to revise and improve its RA penalty structure, there would be no problem.

D. The Commission's Excursion Outside the Scope of Its Jurisdiction Cannot Be Justified by Its Obligation to Provide a CCA the "Earliest Possible Date" for Implementation

The Decision, in its effort to find a solid legal basis for its action, cites the Commission's statutory authority to set the effective date for a CCA planned implementation as an invitation for the Commission to review and base the effective date on a CCA's history of RA deficiencies.[83] The Commission reasons that the RA compliance history demonstrates a CCA's inability to serve its existing customers and therefore is relevant to the planned expansion date.[84] The Commission purportedly justifies this overreach of its authority under 366.2(c)(8)'s requirement that the Commission "designate the earliest possible date for implementation of a community choice aggregation program taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission." Again, this reasoning is misplaced, and the requirement cannot justify the Commission's New Rule.

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83 Decision at 38.

84 *Id.*

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First, the context of the statute makes clear that the "earliest possible date" is something specified *after* an implementation plan is filed. Indeed, this subdivision follows the subdivisions delineating rules for submission of implementation plans ((c)(4)), identification of cost recovery to prevent cost shifts ((c)(5)), notice of implementation plans to the IOU ((c)(6)), and certification of a plan ((c)(7)). In setting the "earliest possible date," the statute expressly provides the only factor the Commission is permitted to consider – "the impact on any annual procurement plan of the electrical corporation that has been approved by the commission."[85] The Commission's New Rule, inserting the evaluation of a CCA's RA compliance history as an additional factor, does not comport with this limitation. The reference to the IOU's approved procurement plan is informed by Section 454.5, which describes in great detail the requirement that an IOU file and submit a procurement plan for Commission approval. The procurement plan is intended to detail the IOUs' "procurement of electricity for its retail customers."[86] Indeed, this requirement is fulfilled by the IOUs' BPPs which are updated periodically.[87] Section 366.2(c)(8) therefore contains a specific requirement intended to ensure that the CCA's implementation will be accounted for vis a vis the relevant IOU's procurement plan.

The New Rule, however, instead will result in the setting of the "earliest possible date" without reference to any approved IOU BPP, but rather to a CCA's RA compliance history. The Decision attempts to rebut the argument that the Commission is limited to considering the bundled procurement plan as set forth in Section 366.2(c)(8) with backbends:

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[85] § 366.2(c)(8).

[86] § 454.5(a). For example, the 2021 Bundled Procurement Plan (BPP) for PG&E approved by the Commission states: " PG&E's BPP describes in detail its planning, procurement, and scheduling and bidding processes, all of which are designed to enable PG&E to provide reliable, cost-effective bundled electric service." PG&E's Bundled Procurement Plan - Public Version (pge.com)

[87] *See, e.g.,* D.12-01-033, *Decision Approving Modified Bundled Procurement Plans*, R.10-05-006 (Jan. 12, 2012): https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/157640.PDF.

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> These arguments ignore that if one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.[88]

However, this very generalized handwaving does not rise to the level of specificity contemplated in Section 366.2(c)(8). There is no specific plan approved by the Commission in question, nor is there any particular explanation of how the CCA's historical RA compliance will affect any such plan. The Commission's defense has no basis.

V. THE DECISION NEEDLESSLY DISCRIMINATES AGAINST CCAS WHEN OTHER, EVEN-HANDED RA ENFORCEMENT ALTERNATIVES ARE AVAILABLE UNDER SECTION 380

The Decision also violates Section 380, needlessly discriminating against CCAs when other less restrictive solutions are available. Section 380(e) requires the Commission to apply its RA program rules even-handedly, by "implement[ing] and enforc[ing] the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner." Section 380(e) requires that "[e]ach LSE shall be subject to the same requirements for [RA]…." In addition, Section 380(b)(4) requires the Commission to "minimize enforcement requirements." Despite these clear directives, the Decision fails to exercise its enforcement powers even-handedly and fails to minimize enforcement requirements despite the availability of less restrictive measures.

The Commission has not applied its new "cure" for RA noncompliance even-handedly to all LSEs. While the Decision applies the New Rule to CCAs and ESPs, it excludes their retail competitors, the IOUs. The Decision attempts to justify this exclusion by pointing to the IOUs' role as POLR.[89] While exempting the IOU in its role as POLR makes sense – the whole point of

[88] Decision at 36-37.
[89] *Id.* at 38-39.

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the POLR is to serve customers other LSEs are no longer serving – the Decision misses a critical point: POLR is only one role among others served by the IOUs.

Beyond the narrow role of POLR, the IOUs, like CCAs and ESPs, serve their own load and are responsible for their RA requirements. SCE and PG&E also serve as Central Procurement Entities (CPEs), bearing responsibility to procure all local RA capacity for all LSEs. The Decision does not explain why the New Rule cannot be applied to the IOUs in these roles.

Moreover, even if there were good reasons to exempt the IOUs entirely from the rule, the inability to apply the rule even-handedly points to a need for a more broadly applicable tool to enforce RA requirements. At least two options fit comfortably within the scope of Section 380: penalties and cost allocation, and no doubt other solutions could be designed within the Commission's authority.

The Commission has to date enforced RA requirements using penalties, and there is no reason that this approach could not be further adapted to serve the Commission's objectives of driving RA compliance. Concerned that "penalty prices below the RA capacity prices may not incentive LSEs to meet system requirements in summer months," the Commission increased penalties in 2020 from $6.66/kilowatt (kW) -month to $8.88/kW-month. [90] In 2021, finding that the "current RA penalty structure does not adequately discourage LSEs from incurring repeated deficiencies,"[91] the Commission added a multiplier point system with increasing penalty levels for repeated deficiencies.[92] Indeed, D.23-06-029 clarifies the operation of the point system.[93]

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[90] D.20-06-031, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, R.19-11-009 (June 25, 2020), at 60-61: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF .

[91] D.21-06-029, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, R.19-11-009 (June 24, 2021), at 59: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

[92] *Id.*, OP 16 at 79.

[93] Decision at 62.

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Improving the existing penalty structure – by raising RA penalties further or accelerating the multiplier effect until the penalty system actually serves its function – seems the most logical course rather than "double penalizing" CCAs by applying penalties and the New Rule. As it stands, the Commission now enforces RA through a penalty structure that is, by their own admission, ineffective.

Beyond penalties, Section 380 also authorizes the Commission to address cost shifting between customer classes in another way. Section 380(b)(3) permits the Commission to "equitably allocate the cost of generating capacity and demand response" in a manner that prevents cost shifts. As set forth above, the Decision justifies its restriction on CCA expansions based on a finding that LSE RA deficiencies result in cost shifts.[94] If the Commission's "cost shift" finding is valid, the Commission should not be restricting CCA expansion as an enforcement tool but should rather utilize its existing and express authority to allocate the cost of "shifted" generation capacity.

The Commission has two central obligations in exercising its enforcement powers pursuant to Section 380(e). It must exercise them "in a nondiscriminatory manner" and "minimize enforcement requirements." D.23-06-029 fails to meet either obligation in adopting the expansion restriction for CCAs and ESPs. Moreover, the Commission ignores the clear "cure" for cost shifting provided by Section 380: cost allocation. The Decision's exercise of its enforcement powers to prevent CCA expansion exceeds the Commission's jurisdiction under Section 380, and results in the Commission not acting in accordance with law.

94 *Id.*, FOF 6, at 130.

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VI. THE COMMISSION ABUSES ITS DISCRETION AND FAILS TO ACT IN THE MANNER REQUIRED BY LAW BY MAKING FINDINGS THAT ARE UNSUPPORTED BY THE RECORD

The Decision's findings on grid reliability in support of its New Rule are conclusory and unsupported by the record. The Commission summarily rendered its findings not only without support and reasoning but in the face of contrary evidence. RA is transacted in a complex, bilateral market under FERC jurisdiction warranting significantly greater analysis than the Decision affords. The Decision's superficial, unstudied conclusions cannot form the basis of a reasonable decision and, instead, constitute an abuse of its discretion, and a failure to act in the manner required by law.

A. The Commission Errs in Summarily Concluding that Compliant LSEs are Subsidizing Deficient LSEs' Energy Procurement

The Decision justifies its New Rule based on the purported impacts LSE deficiencies have on other LSEs. Finding of Fact 6 provides: "LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting." [95] The Decision attempts to support this Finding of Fact with two conclusory statements unsupported by any explanation or evidence.

First, the Decision concludes:

> [I]f one LSE fails to contract for resources to serve its own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.[96]

Nothing in the decision explains how or the extent to which such a subsidy occurs. The Decision fails to identify any direct evidence of a subsidy.[97] The deficient LSE by definition did not

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95 *Id.*, FOF 6 at 130.

96 *Id.* at 37.

97 "Subsidize" means "to purchase the assistance of by payment of a subsidy: *Merriam-Webster Dictionary*.

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purchase the RA, so other LSEs are not "subsidizing" the deficient LSE's procurement. Neither do other LSEs subsidize the deficiency by procuring backstop resources to account for the deficiency; indeed, backstop responsibility lies with the California Independent System Operator (CAISO) under its FERC-regulated tariff.[98] Under the tariff, the CAISO has the authority to procure RA capacity to cure the deficiency and charge the cost of the backstop to the deficient LSE.

Second, the Decision concludes that:

> LSEs that are deficient in their RA obligations result in leaning on other LSEs' procurement activities and impairing grid reliability by failing to secure resources to support their existing customer base.[99]

The decision does not define "leaning" nor explain how it occurs. Other LSEs procure only for their own customers, and all LSEs, including deficient LSEs, contribute to procurement of additional resources as "excess Planning Reserve Margin" by paying for it through the Cost Allocation Mechanism.[100] Similarly, all taxpayers pay for the costs of the DWR Strategic Reliability Reserves to provide emergency reserves.[101] Other LSEs do not procure capacity to fill a deficiency by the deficient LSE. As CalCCA pointed out in its Comments on the Proposed Decision resulting in D.23-06-029 and the New Rule, if there is "leaning," the Commission caused it by failing to rely on existing regulatory mechanisms intended to solve this problem.[102] Had the Commission simply relied on the established backstop process, the CAISO under a

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98 CAISO Tariff Section 43A - Capacity Procurement Mechanism as of August 15, 2022: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf.

99 Decision at 37-38.

100 *Id.* at 25.

101 Cal. Pub. Res. Code § 25793(a).

102 *See California Community Choice Association's Comments on the Proposed Decision*, R.21-10-002 (June 14, 2023), at 6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M511/K502/511502590.PDF.

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FERC jurisdictional tariff would have procured any necessary resources and allocated the costs directly to LSEs deficient in their RA obligations.[103]

The Commission's findings and conclusions pointing to leaning or subsidies are not only unsupported, but also incorrect. The Commission's repeated conclusory assertions regarding such leaning or subsidies do not make them true – the Commission is required to justify such assertions and findings with reasoned evidence and support. The Decision's complete lack of such evidence and support of Finding of Fact 6 and other findings and conclusions concerning the existence of leaning or subsidies constitutes an abuse of discretion, and a failure of the Commission to act in accordance with law.

B. The Commission Errs in Summarily Concluding that Allowing LSEs Deficient in Meeting RA Requirements to Expand or Otherwise Take on New Customer Load is Detrimental to Grid Reliability

The abuse of discretion highlighted in Section VI.A above is exacerbated by the Commission's conclusion that "[a]llowing LSEs that cannot meet their existing RA obligations to expand their territory or to otherwise take on new customer load is detrimental to grid reliability."[104] Once again, the Commission has failed to connect the dots; it does not explain the connection between an LSE's deficiency and grid reliability, and ignores contrary evidence.

The Commission provides no response to important points raised by CalCCA in the RA Rulemaking on this issue. First, an expansion only moves customers from one LSE to another and does not alter the demand or supply for RA capacity. [105] The LSE losing customers has a lower need for RA capacity, while the LSE gaining customers has an increased need, with a net

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[103] CAISO Tariff Section 43A.8: https://www.caiso.com/Documents/Conformed-Tariff-as-of-May1-2023.pdf.

[104] Decision, FOF 6 at 130.

[105] *See California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, R.21-10-002 (Feb. 24, 2023), at 25: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K756/502756803.PDF.

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zero effect on demand. Likewise, it has no effect on the supply available to meet California's energy needs. Second, even if an LSE's individual deficiency were to impact grid reliability, the CAISO has the authority to mitigate that impact by backstopping the deficiency under its tariff and imposing the associated costs on the deficient LSE.[106]

The Decision fails to address these points and to connect the dots between a single LSE's RA compliance deficiency and grid reliability. The Decision's lack of evidence and reasoning to support its finding regarding grid reliability constitutes an abuse of discretion by the Commission, as well as a failure to act in accordance with law.

VII. CONCLUSION

For the foregoing reasons, the Commission should grant rehearing to correct each of the legal errors specified in this Application for Rehearing of Decision 23-06-029.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

July 26, 2023

[106] CAISO Tariff Section 43A.2.3 and 43A.8: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf.

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EXHIBIT 6

D.23-12-038: Order Denying Rehearing of Decision 23-06-029 and Motion for Partial Stay

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Decision D.23-12-038 December 14, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002

ORDER DENYING REHEARING OF DECISION 23-06-029 AND MOTION FOR PARTIAL STAY

I. INTRODUCTION

On July 26, 2023, California Community Choice Association (CalCCA) filed a timely application for rehearing of Decision (D.) 21-10-002 (Decision). On August 4, 2023, two other separate and timely applications for rehearing of the Decision were filed. The first was filed by Shell Energy North America (US), L.P. (Shell Energy) together with The Alliance for Retail Energy Markets' (AreM) (collectively, ESP Parties). The second was filed by the California Efficiency + Demand Management Council, Leapfrog Power, Inc., OhmConnect, Inc., CPower, Enel X North America, Inc., and Center for Energy Efficiency and Renewable Technologies (collectively, Joint Parties). In the Decision, we adopted Local Capacity Requirements for 2024-2026, Flexible Capacity Requirements for 2024, and refinements to the Resource Adequacy program, including modifying the planning reserve margin for 2024 and 2025 and modifying the demand response (DR) counting requirements. As relevant to the Applications, we prohibited any community choice aggregator (CCA) or electric service provider (ESP) with a deficiency of greater than 1 percent of its system resource adequacy (RA) requirement on a month ahead RA filing during the previous two calendar

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years from expanding its operations or taking on any new customers for the following year (RA Deficiency Rule or the Rule).

The RA Deficiency Rule arose from a repeated failure by load-serving entities (LSEs) to meet their RA requirements while seeking to expand their service territories. Seven LSEs received month-ahead RA deficiencies in 2021 and five LSEs received month-ahead RA deficiencies in 2022. Energy Division (ED) staff expressed concern with deficient LSE expansions that could (1) jeopardize reliability; (2) result in leaning on compliant LSEs; (3) undermining the purpose of the effective Planning Reserve Margin (PRM). ED also submitted its recommendations for adjustments to the DR program in a proposal that was the subject of comments and reply comments by parties.

In the first application for rehearing of the Decision, CalCCA asserts that RA Deficiency Rule is in error because the Commission lacks jurisdiction to limit expansion based on past RA deficiencies or prevent customers from aggregating their energy load pursuant to Public Utilities Code sections 366.2, 365.1, and 380.[1] CalCCA also asserts that through the RA Deficiency Rule, we have exceeded our statutory authority to prevent cost shifting or to set the earliest possible effective date for CCA program implementation. Moreover, according to CalCCA, the RA Deficiency Rule violates section 380 by discriminating against CCAs and is unsupported by sufficient evidence in the record.

In the second application for rehearing, the ESP Parties raise similar arguments as CalCCA but with respect to ESPs. Specifically, they argue that we lack statutory authority to restrict Direct Access load migration and are not aided by our authority to suspend and revoke ESP registration. Like CalCCA, ESP Parties also argue that the RA Deficiency Rule is discriminatory to LSEs pursuant to section 380 and is unsupported by sufficient record evidence.

[1] All further references are to the Public Utilities Code unless noted otherwise.

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In the third application for rehearing, Joint Parties allege that the Decision committed legal error in determining: (1) whether D.23-06-029 contravenes D.16-09-056 by giving clear preference to Investor Owned Utility (IOU) DR programs, to the detriment of third-party DR, (2) a rule change to take "immediate effect," eliminating Reliability Demand Response Resource (RDRR[2]) as an emergency resource, that is wrongly characterized as a "clarification" of existing policy, which is not supported by any finding of fact or included in any ordering paragraph; (3) the elimination of the Transmission Load Factor (TLF) and the Planning Reserve Margin (PRM) Adders; (4) the expansion of the Proxy DR (PDR) availability requirement; and (5) derating third-party DR qualifying capacity (QC) values based on test results outside of the current QC valuation process. Joint Parties also filed a motion for partial stay, reiterating the claims of legal error in the application for rehearing, and requesting an immediate stay of the Decision. Joint Parties also requested that the Commission hold oral argument on their application for rehearing. The California Large Energy Consumers' Association (CLECA) filed a response in support of the Joint Parties' Application and Motion.

We have carefully considered all the arguments presented by rehearing applicants and are of the opinion that rehearing of the Decision is not warranted, as explained below. Each of the applications for rehearing of the Decision, therefore, is denied. Joint Parties' request for oral argument and motion for partial stay are also denied.

II. DISCUSSION

A. CalCCA Application for Rehearing.

1. Commission's Jurisdiction.

a) Public Utilities Code section 380.

CalCCA asserts that we acted without jurisdiction in adopting the RA Deficiency Rule because the relevant statutes do not expressly authorize the RA

[2] RDRR was referred to in D.10-06-034 as Reliability Demand Response Product or RDRP.

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Deficiency Rule. (CalCCA Rehg. App., pp. 6-23.) Specifically, CalCCA argues that: (1) our authority over CCAs must be expressly granted and delineated by the Legislature and does not extend to enacting the RA Deficiency Rule and (2) sections 366.2, 365.1, and 380 do not require harmonization or support the RA Deficiency Rule. CalCCA's arguments fail to establish legal error for the following reasons.

We derive our power from the California Constitution and the Legislature. "The Legislature has plenary power, unlimited by the other provisions of this constitution but consistent with this article, to confer additional authority and jurisdiction upon the commission ...." (Cal. Const., art. XII, § 5.) Exercising this plenary power, the Legislature enacted the Public Utilities Act (§ 201 *et seq*.). Yet, "the commission's powers are not limited to those expressly conferred on it: the Legislature further authorized the commission to '*do all things,* whether specifically designated in [the Public Utilities Act] *or in addition thereto,* which are necessary and convenient' in the exercise of its jurisdiction over public utilities. [Citations.] Accordingly, 'The commission's authority has been liberally construed' [citations], ….'" (*San Diego Gas & Electric Co. v. Superior Court* (1996) 13 Cal.4th 893, 915.) (A further discussion of the fact that CCAs are not public utilities follows in the section below.) There are two limits on this principle of liberal construction. The first provides that "[a]dditional powers and jurisdiction that the commission exercises … 'must be cognate and germane to the regulation of public utilities.'" (*Consumers Lobby Against Monopolies v. Public Utilities Com.* (1979) 25 Cal.3d 891, 905–906.) The second is that section 701 does not authorize us to disregard express legislative directions or restrictions upon its powers found in other statutes. (*Assembly v. Public Utilities Com.* (1995) 12 Cal.4th 87, 103.)

While the deference rule does not apply where the scope of our powers and jurisdiction is at issue (*BullsEye Telecom, Inc. v. California Public Utilities Com.* (2021) 66 Cal.App.5th 301, 309), the courts may "tak[e] into account" agency interpretations. (*Yamaha Corp. of America v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 8.) The weight given to agency interpretations is "contextual," and depends on factors such as "'the thoroughness evident in [the agency's] consideration, the validity of its reasoning,

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its consistency with earlier and later pronouncements, and all those factors which give it power to persuade, if lacking power to control. [Citation.]' " (*Id.* at pp. 14–15.)

CalCCA asserts that we do not have jurisdiction to enact the RA Deficiency Rule absent "express legislative authority for the Commission action at issue." (CalCCA Rehg. App., p. 8.) In fact, section 380 sets out our authority and legislative directives regarding RA programs. It states that we "shall establish resource adequacy requirements for all load-serving entities," including investor-owned utilities (IOUs), electric service providers (ESPs), and community-choice aggregators (CCAs). LSEs are required to submit annual and monthly filings to demonstrate compliance with the applicable RA requirements. (Pub. Util. Code, § 380, subd. (f).) Section 380 authorizes us to "implement and enforce" the RA requirements "in a nondiscriminatory manner" and to "exercise its enforcement powers to ensure compliance by all load-serving entities." (Pub. Util. Code, § 701, subd. (e).) We have established a citation program for LSEs who fail to comply with these requirements. (See D.21-06-029.)

Section 380's purpose was to "ensure that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves at just and reasonable rates." (Assem. Com. Utilities and Commerce, hearing analysis of Assem. Bill No. 380 (2005-2006 Reg. Sess.) as amended April 12, 2005, p. 1.) It was also "to develop a mechanism to ensure no shifting of costs" between an IOU's customers and "the customers on whose behalf they were incurred…." (*Ibid*.) The legislative comments explained that "[i]f the ESPs do not adequately provide for the demands of its customers, the customers of the IOU end up paying more for electricity." (*Id*. at p. 2.) The purpose of RA requirements "is to ensure that each retail electric service provider has sufficient resources available to ensure reliable service under adverse conditions." (*Id*. at p. 3.) "If the ESP has failed to procure enough resources, the customer continues to draw electricity from the IOU's reserves, which compromises reliability for the IOU's customers, or increases costs across all of its customers if the IOU has to purchase additional resources on the spot market for these unanticipated customers." (*Id*. at p. 3.) Both the plain language of section 380 and the legislative

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history demonstrate the Legislature's concerns with system reliability and cost shifting caused by non-IOU LSEs. There is no indication that the Legislature somehow intended to limit our authority to effectuate these and other stated goals. Section 380, therefore, plainly authorizes us to set RA requirements and discipline CCAs who fail to comply.

As the Decision notes, "LSEs are continuing to fail to meet RA obligations." (Decision, pp. 35-36.) Some of these deficient LSEs seek to expand their program "even as they have been unable to secure sufficient capacity to meet their RA obligations and serve their existing customers." (Decision, p. 36.) The broad language of section 380 enables us to determine, in our discretion, the best enforcement mechanism for the RA program. Section 701 empowers us to "do all things, whether specifically designated in [the Public Utilities Act] or in addition thereto, which are necessary and convenient' in the exercise of its jurisdiction" over public utilities (*San Diego Gas & Electric Co. v. Superior Court, supra*, 13 Cal.4th at p. 915) ***and entities adjacent to public utilities***. (*PG&E Corp. v. Public Utilities Com.* (2004) 118 Cal.App.4th 1174.) That is, because section 380 authorizes us to establish RA requirements and enforce them, we may do all that is necessary and convenient to compel compliance, including preventing further expansion.

Otherwise, it would make "little sense to grant the Commission authority over protecting the public interest through conditions and mitigation measures, but not allow it to exercise its traditional functions to oversee and enforce those measures." (*PG&E, supra*, 118 Cal.App.4th at p. 1196.) "The primary limiting factor on PUC jurisdiction is that the PUC's action must be cognate and germane to utility regulation." (*Id.* at p. 1201.) We are obligated to intervene where "[CCA] program elements may affect utility operations and the rates and services to other customers." (D.05-12-041, at *8-9.) This is because we "retain[s] a responsibility to assure that a CCA's policies, practices and operations do not compromise the operations of the utility or service to utility customers." (D.05-12-041, at *11.) As explained in the Decision, the purpose of the RA Deficiency Rule is "to ensure that LSEs procure sufficient capacity to meet their customer loads, maintain electrical grid reliability, and prevent deficient LSEs from

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increasing risk of grid emergencies arising from lack of resources bidding into CAISE's wholesale markets." (Decision, p. 38.) The RA Deficiency Rule, therefore, does not seek to regulate CCAs but is, instead, "cognate and germane" to ensuring "that a CCA's policies, practices and operations do not compromise the operations of the utility or service to utility customers." (D.05-12-041, at *11.)

Notwithstanding section 701, the Legislature deferred to our expertise in resource adequacy and granted us considerable discretion to determine what actions are necessary to accomplish the stated goals. At that point, we were enabled with "the authority to employ all necessary means to accomplish the end is always one of the implications of the law." (*Wendz v. California Department of Education* (2023) 93 Cal.App.5th 607, 622.)

Assembly v. Public Utilities Com., *supra*, 12 Cal.4th 87 and *Pacific Tel. & Tel. Co. v. Public Util. Com.* (1965) 62 Cal.2d 634, are inapplicable here for the reason enunciated in *PG&E*: "In both *Assembly* and *Pacific Tel. & Tel. Co.,* section 701 was inapplicable because the actions of the PUC disregarded 'express legislative directives.' [Citations.] Here, by contrast, the holding companies fail to point to any statutory mandate or directive forbidding the PUC from enforcing the holding company conditions, and we are aware of none." (*PG&E, supra,* 118 Cal.App.4th at p. 1199.) In *Assembly v. Public Utilities Com.*, for example, the Commission "attempted to rely on section 701 as authority to direct ratepayers refunds from Pacific Bell to a school telecommunications infrastructure fund, despite an express statutory mandate (§ 453.5) that such refunds be returned to ratepayers." (*Assembly v. Public Utilities Com.*, *supra*, 12 Cal.4th at pp. 102–104.) In *Pacific Tel. & Tel. Co.,* the Commission "directed a utility to refund to ratepayers amounts collected under a previously approved rate schedule based on the PUC's conclusion that past rates should have been lower, notwithstanding express direction from the Legislature that the PUC's orders fixing rates must be prospective only." (*Pacific Tel. & Tel. Co., supra,* 62 Cal.2d at pp. 649–650, 653.) These cases demonstrate that,, absent an express legislative directive to the contrary,

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section 701 supports our authority to "do all things, … which are necessary and convenient in the exercise" of its authority under section 380.

b) Public Utilities Code sections 366.2, 365.1, and 380.

CalCCA asserts that we erred in relying on a harmonization of sections 366.2, 365.1, and 380 because they each "serve unique, separate, and nonconflicting purposes" and do not provide us with jurisdiction to enact the RA Deficiency Rule. (CalCCA Rehg. App., pp. 8-13.) CalCCA misunderstands the RA Deficiency Rule.

Rules of statutory interpretation requires that "the plain and commonsense meaning" of the statutory language is considered "in the context of the statutory framework as whole in order to determine its scope and purpose and to harmonize the various parts of the enactment." *(Coalition of Concerned Communities, Inc. v. City of Los Angeles* (2004) 34 Cal.4th 733, 737.) "[A] statute can be read as a whole, and its various parts harmonized so as to give effect to legislative intent. Whenever possible, effect should be given to every word, phrase, and clause so that no part or provision will be useless or meaningless. [Citations.]" (*Smith v. Regents of University of California* (1976) 58 Cal.App.3d 397, 403.) "Thus, when two codes are to be construed, they must be regarded as blending into each other and forming a single statute." (*State Dept. of Public Health v. Superior Court* (2015) 60 Cal.4th 940, 955 [internal citations and quotation marks omitted].)

First, as we explained in the Decision, subdivisions (b)(4) and (5) clarify "that CCAs must prepare to fully supply electricity to their customers and may not shift costs for energy to the customers of other LSEs by failing to contract in advance for such capacity." (Decision, p. 37.) Moreover, subdivision (*l*)(1) empowers us to authorize an IOU to terminate CCA services. That section 366.2 contains limitations on CCAs' operations also dispels CalCCA's unsupported argument that section 366.2(a)(1) confers an absolute statutory right to aggregate on potential customers. (CalCCA Rehg. App., p. 3.) In applying AB 117's mandates, we explained that our authority over CCAs is the same as the "authority we have over any individual or entity whose acts or knowledge are

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germane to our regulatory obligations." (D.05-12-041, at *11.) We also retain "a responsibility to assure that a CCA's policies, practices and operations do not compromise the operations of the utility or services to utility customers." (*Ibid*.) So, contrary to CalCCA's characterization, section 366.2 empowers us to regulate CCAs to the extent that their procurement deficiencies affect other customers and IOUs. The RA Deficiency Rule is not an expansion of our jurisdiction over CCAs but an enforcement of existing scope of authority.

Second, section 380 sets out our authority and legislative directives regarding RA programs. It is the operative statute under which we establish the RA Deficiency Rule. Pursuant to section 380, we establish RA obligations applicated to all LSEs, including IOUs, ESPs, and CCAs. Section 380 unequivocally authorizes us to "implement and enforce" the RA requirements. (Pub. Util. Code, § 380, subd. (e).) Thus, the RA Deficiency Rule is an application of our already existing authority over CCAs.

We have statutory authority to "do all things, … which are necessary and convenient in the exercise" of its power under sections 366.2 and 380 so long as those actions are not contrary to express legislative directives. Put another way, once the Legislature delineated to us certain powers and responsibilities, we are empowered take all actions necessary to exercise those powers and enforce such responsibilities. This includes ensuring that CCAs is responsible for all of its customers' procurement needs and complies with the RA requirements.

Third, section 365.1 further informs the Decision. CalCCA asserts that section 365.1 does not support the imposition of the RA Deficiency Rule because "the section seems irrelevant to the question at hand given that it predominantly governs direct access." (CalCCA Rehg. App., p. 13.) But while section 365.1 may not be directly relevant to CCAs, it is relevant to Energy Service Providers (ESP)—the other entities subject to the RA Deficiency Rule. Section 365.1 is discussed at length in the second half of this memorandum addressing ESP Parties' rehearing application.

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2. Cost shifting.

CalCCA argues that the sole remediation against improper cost shifting is through the Power Charge Indifferent Adjustment (PCIA) proceedings and the Cost Allocation Mechanism (CAM). (CalCCA Rehg. App., pp. 15-17.) However, these cost recovery mechanisms—or any other that we may choose to promulgate—are tangential to the RA Deficiency Rule. The RA Deficiency Rule is predicated on section 380 and a history of RA violations, not purported cost shifts as CalCCA mistakenly believes. The Decision discusses cost shifting as one of the possible effects of RA violations.

3. Earliest possible effective date.

CalCCA argues that section 366.2(c)(8)'s requirement that we "designate the earliest possible date for implementation of a community choice aggregation program" does not authorize the Commission to base the earliest possible effective date on RA compliance. (CalCCA Rehg. App., p. 21.) But this argument again misconstrues the premise for the RA Deficiency Rule: it is based on the Commission's RA implementation and enforcement authority under section 380. As explained in the Decision, the "earliest possible effective date" is relevant only to the extent that Energy Division is unable to confirm the expansion date until after past RA compliance has been confirmed. (Decision, pp. 42, 115, 138-139.) The RA Deficiency Rule acts upon the Commission's RA authority and harmonizes it with the Commission's jurisdiction in other matters over CCAs, espoused in sections 366.2 and 366.3, to effectuate the Legislature's intent.

The RA Deficiency Rule does not seek to set an effective date based on a CCA's compliance thus whether an implementation plan is filed or not is irrelevant. (See CalCCA Rehg. App., pp. 22-23.) Instead, it is "a reasonable, measures approach to enforcing the Public Utilities Code, including Section 380, to ensure grid reliability through Resource Adequacy compliance." (Decision, p. 37.)

Moreover, contrary to CalCCA's argument, the fact that the Legislature specifically listed consideration of a procurement plan as a basis for specifying the

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"earliest possible date" does not mean that we may only consider that factor.[3] We have rejected this exact argument previously. (See D.20-01-030, at *52-53, fn. 109.) CalCCA does not address D.20-01-030 or cite any authority that would support such its interpretation. To the contrary, any such reading would be "inapplicable where its operation would contradict a discernible and contrary legislative intent." (*California Fed. Savings & Loan Assn. v. City of Los Angeles* (1995) 11 Cal.4th 342, 351.)

4. Discrimination pursuant to Public Utilities Code section 380.

As it did in its comments, CalCCA argues that the RA Deficiency Rule discriminates against CCAs and ESPs in purported violation of section 380. (CalCCA Rehg. App., pp. 23-25.) We explained that "[t]he Public Utilities Code creates a variety of distinctions between different classes of LSEs," and lists IOUs are one example, given their role as the Providers of Last resort (POLR) whereas CCAs and ESPs are "permitted to return their customers" to the IOUs. (Decision, p. 39.)

A POLR is "a load-serving entity that the commission … designates to provide electrical service to any retail customer whose service is transferred to the designated load-serving entity because the customer's load-serving entity failed to provide, or denied, service to the customer or otherwise failed to meet its obligations." (Pub. Util. Code, § 387, subd. (a)(3).) "A POLR is the utility or other entity that has the obligation to serve all customers." (R.21-03-011, *Order Instituting Rulemaking to Implement Senate Bill 520 & Address Other Matters Related to Provider of Last Resort* (Mar. 18, 2021), at *1.) "Like IOUs, the ESPs and CCAs must procure sufficient power for their customers and recover the costs of that procurement. Unlike IOUs, ESPs and CCAs have the discretion to determine the terms and price for procured power without

[3] The Applicants are averring to a principle of statutory construction referred to as *inclusio unius est exclusion alterius* ("the expression of one thing is the exclusion of another"). (See *Murillo v. Fleetwood Enterprises, Inc.* (1998) 17 Cal.4th 985, 991 ["This rule of statutory construction, although useful at times, is no more than a rule of reasonable inference and cannot control over the plain meaning of the statutory language."].)

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Commission review." (*Id*. at *4-5.) And, unlike ESPs and CCAs, "IOU procurement is subject to various levels of reasonableness review by the Commission." (*Ibid*.) "This close review [of IOUs] provides the opportunity to correct course if resources fail to materialize or effectively meet system needs. The retail rates charged by the IOUs are also closely reviewed to ensure they are just and reasonable. This oversight is necessary to ensure safe and reliable public utility electricity service at just and reasonable rates, consistent with Public Utilities Code Section 451." (*Ibid*.)

The three major IOUs are the POLR in their service territories. That means their procurement is subject to stringent review to ensure that IOUs meet their procurement requirements. CCAs and LSEs are not subject to the same standards. As the Decision points out, this is a legal distinction, and it is not discriminatory for our rules to reflect such distinctions. CalCCA does not argue that the distinct requirements for IOUs and CCAs are discriminatory. Instead, it suggests that we apply the RA Deficiency Rule to the IOUs in their non-POLR role. (CalCCA Rehg. App., p. 23.) It is unclear how we might achieve this and it is more reasonable to impose requirements based on legal distinctions as is occurring already.

CalCCA further asserts that to combat the purported discrimination in the RA Deficiency Rule, we should simply come up with "a more broadly applicable tool to enforce RA requirements [that] … fit comfortably within the scope of Section 380" such as "penalties and cost allocation." (CalCCA Rehg. App., p. 24.) But we have already employed these approaches—as CalCCA necessarily recognizes—to no avail. (Decision, p. 35.) CalCCA suggests that these approaches need to be "further adapted to serve the Commission's objectives of driving RA compliance." (CalCCA Rehg. App., pp. 24-25.) There is nothing constricting us from pursuing different strategies if the present ones are not sufficiently tailored to achieve our mandates. Moreover, neither penalties nor cost allocation would directly address the Legislative's concerns in enacting section 380—ensuring grid reliability.

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5. Sufficiency of the record.

CalCCA also argues that the Decision's findings regarding grid reliability and the effects of LSEs' under-procurement are conclusory and unsupported by the record. (CalCCA Rehg. App., pp. 26-29.) Specifically, CalCCA objects to Finding of Fact (FOF) 6 which states:

> Allowing LSEs that cannot meet their existing RA obligations to expand their territory or to otherwise take on new customer load is detrimental to grid reliability. LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost shifting. (Decision, p. 130.)

CalCCA argues that FOF 6 is in error because (1) there is no evidence of a subsidy by non-deficient LSEs of a deficient LSE so there is no basis to conclude that grid reliability may be impacted (CalCCA Rehg. App., pp. 25-26) and (2) the Decision does not explain how deficient LSEs are "leaning on other LSEs' procurement activities and impairing grid reliability" (CalCCA Rehg. App., pp. 26, 28).

A party challenging a Commission's finding for lack of substantial evidence must demonstrate that, based on the evidence before the Commission, a reasonable person could not reach the same conclusion. (*The Ponderosa Telephone Co. v. Public Utilities Com.* (2019) 36 Cal.App.5th 999, 1013.) "It is for this reason that the Commission's factual findings are almost always treated as 'conclusive' [citations], 'final and not subject to review.' [Citations.]." (*Pacific Gas & Electric Co. v. Public Utilities Com.* (2015) 237 Cal.App.4th 812, 839.)

"A court must ensure that an agency has adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute." (*Cal. Hotel & Motel Ass'n v. Indus. Welfare Comm'n* q 25 Cal.3d 200, 212.) There is a "strong presumption of the correctness of the findings and conclusions of the commission, which may choose its own criteria or method of arriving at its decision, even if irregular, provided unreasonableness is not 'clearly established.'" (*The Ponderosa Telephone Co. v. Public Utilities Com.*, *supra*, 36 Cal.App.5th at p. 1029.) Substantial evidence includes not only direct

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evidence, but also circumstantial or indirect evidence and all reasonable inferences flowing therefrom. (*County of Kern v. Jadwin* (2011) 197 Cal.App.4th 65, 72–73.)

The evidence in the record demonstrates that seven LSEs received month-ahead RA deficiency citations in 2021 and five LSEs received month-ahead RA deficiency citations in 2022. (Decision, pp. 30-31, citing Energy Division Phase 3 Proposal.) Leading up to these deficiencies, the California Independent System Operator (CAISO) had to institute unplanned rotating electricity outages in California in August 2020 which demonstrated "that the state's reliability issues are acute and immediate…." (PG&E Opening Comments at 9, citing D.21-06-033, at *3.) As a result of these concerns, we had decided against expansion of Direct Access because it "would further fragment the market, which in turn could exacerbate the planning and related activities necessary to ensure grid reliability." (D.21-06-033, at *3.) We explained that "in the coming years load serving entities will need to invest in … new generation resources through long-term contracts to ensure grid reliability." (*Id*. at p. *4.) The severe heat events also occurred in 2021 and 2022, leading to "significant stress on the grid that required California to rely on every available resource to prevent electric outages." (Decision, p. 35, citing Energy Division Phase 3 Proposals, at p. 34.) The evidence of the heat events and our prior actions regarding Direct Access reasonably inform the Decision's consideration of LSE expansions.

CAISO—the entity responsible with maintaining reliability and operating California's wholesale energy market—also opined that "it is critical that the Commission prioritize planning and procurement reforms to ensure reliability going forward." (March 3, 2023, CAISO Reply Comments, at p. 3.) CAISO stated that "[i]deally, LSEs will contract with a significant portion of the needed resources well in advance, such that incremental procurement required in the annual timeframe is minimized and limited to address, for example, small changes to load forecasts." (*Ibid*.)

CalCCA argued that the RA deficiencies were a product of a "severely constrained RA market conditions" (February 24, 2023, CalCCA Comments, at p. 5), whereas PG&E asserted that it "conducted a similar stack analysis and found different

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results, specifically that there are sufficient resources available in each month in question to meet the RA program requirements, albeit with some months being tight." (March 3, 2023, PG&E Comments, at pp. 1-2.) As PG&E also correctly noted, "[w]hile some of system RA capacity may be expensive, LSEs already have the ability not to procure and pay the penalty price instead." (*Id*. at p. 4.)

PG&E explained that if CCAs are not required to comply with RA requirements, it would result in a process "fraught with free-rider (i.e., leaning) and market pricing issues." (March 3, 2023, PG&E Comments, at p. 4). And, if CCAs can elect not to comply with the RA requirements (and only pay the fine *post hoc*), "it turns the effective planning reserve margin ('PRM') into a backstop mechanism, as it would not make sense for the effective PRM to also be subject to that same price cap, resulting in the IOU procuring RA-eligible capacity for all LSEs that other LSEs chose not to procure…." (*Id*. at p. 5.) Southern California Edison asserted that "adequacy of resources directly affects an ESP's capability to operate." (SCE Reply Comments, at p. 4.)

CalCCA argues that there is no evidence of a "subsidy" in the record since "[t]he deficient LSE by definition did not purchase the RA…." (CalCCA Rehg. App., pp. 26-27.) CalCCA also asserts that the Decision "does not define 'leaning' nor explain how this occurs" since "LSEs procure only for their own customers, and all LSEs, including deficient LSEs, contribute to procurement of additional resources…." (CalCCA Rehg. App., p. 27.) CalCCA's reading of the Decision and the record here is extremely narrow. When a CCA (or any LSE) underprocures, excess procurement must be used to backfill the capacity not provided by the deficiencies. The deficient CCAs avoid paying for the RA resources and, instead, rely on other LSEs to provide reliability capacity that the CCAs should have acquired directly. In D.04-01-050, we established the Planning Reserve Margin (PRM) as an obligation for LSEs to procure generation capacity over and above the capacity required to meet peak demand. The purpose of the reserve margin was to ensure there would be sufficient energy capacity to meet peak demand plus needed operating reserves "since at any given time some percentage of

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plants may not be available due to such factors as maintenance, forces outages, fuel limitations, or in the case of hydroelectric power, insufficient water." (D.04-01-050, at *21.) The appropriate PRM is set on the assumption that all LSEs would meet their RA requirements and was not set to provide backfill for deficient LSEs. Thus, when a CCA fails to procure for its own customers, this results in "leaning" on the excess procurement that is paid for by all customers and, instead of supplying the full intended benefit of an additional buffer of reliability accruable to all customers, results in partial subsidy to the deficient CCA.

Based on the record before it, we reasonably concluded that if a CCA is unable to provide for its existing customers' capacity, a further expansion of the customer base would further exacerbate the cycle of "leaning" on to other LSEs' procurement and be detrimental to section 380's goal of grid reliability.

B. ESP Parties' Application for rehearing.

1. Commission Jurisdiction.

ESP Parties argue that the RA Deficiency Rule violates the Direct Access (DA) statutory scheme because we may not bar retail customers from seeking service from registered ESPs. (ESP Parties Rehg. App., pp. 3-4.) In particular, ESP Parties assert that the legislative history and our prior interpretation of the Direct Access scheme does not allow us "to bar nonresidential retail customers from contracting with certain ESPs." (ESP Parties Rehg. App., p. 7.)

Direct Access is an electric service option that allows retail customers to buy electricity from an Energy Service Provider (ESP). Direct Access became available to customers as part of energy deregulation enacted by AB 1890 (Brulte, 1996). Originally, Direct Access was intended to be a choice available to all customers. However, in the wake of the 2001 energy crisis, the State capped the amount of load that can be served by Direct Access providers and limited new enrollment to non-residential customers. (D.21-06-033, at *5.) AB 1X (Keely, 2001) suspended new customers from participating in Direct Access service. SB 695 (Kehoe, 2009) opened Direct Access to a limited amount of new load to non-residential, which was phased in over 2010 to 2013. SB 695

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also created a capacity "cap" of the amount of load eligible for Direct Access and formed the Direct Access Lottery system that allowed for new non-residential customers to participate in the program.

The most current statue that modified the Direct Access program was SB 237 (Hertzberg, 2018). As amended, section 365.1 provided that "[t]he commission shall authorize individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatthours annual limit." (Pub. Util. Code, § 365.1, subd. (b).) Subdivision (d)(3) provides that section 365.1 "does not supplant the resource adequacy requirements of Section 380 or the resource procurement procedures established in Section 454.5." Subdivision (e) instructs us to establish the maximum allowable annual limit, implement a reopening schedule, and "review and, if appropriate, modify its currently effective rules governing direct transactions…." Subdivision (f) instructed us to "provide recommendations to the Legislature on implementing a further direct transactions reopening schedule," based on our analysis of four distinct factors including ensuring system reliability and prohibiting cost shifting. SB 237 was implemented in two phases. Phase I resulted in D.19-05-043, wherein we ordered an additional 4,000 GWh of Direct Access load and which went into effect January 1, 2021. Phase II resulted in D.21-06-033, wherein we recommended against further Direct Access expansion because it was unable to make the required statutory findings. Specifically, we concluded "that at this time, expansion of Direct Access to all non-residential customers would present an unacceptable risk to the state's long-term reliability goals." (D.21-06-033, at *2.)

The RA Deficiency Rule is propagated pursuant to our section 380 resource adequacy authority. While section 365.1 does not expressly provide for our authority to approve or disapprove current ESPs' expansion, the Legislature has expressly deferred to us the determination of the maximum allowable total kilowatthours annual limit, resource adequacy mechanisms, and appropriateness of implementing a further direct transactions reopening schedule (among other tasks). We had determined that further expansion of

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Direct Access is currently inappropriate due to significant grid reliability concerns. (See D.21-06-033.) Moreover, SB 237's legislative history reflects significant and persistent concerns with expanding Direct Access "given the shaky status of RA" since "California's electric system is undergoing significant structural changes that include integrating greater numbers of intermittent renewable resources, repowering or retiring over 16 gigawatts of gas-fired power plants that rely on once-thorough cooling (OTC) technology, and an increasing number of resources that will surpass their design life in the coming years." (Assem. Utilities and Energy Com., com. on Sen. Bill No. 237 (2017-2018 Reg. Sess.) June 13, 2018, p. 3.) The Legislature also noted that,

> If California RA policies fail to provide sufficient resources, the CAISO may be forced to utilize centralized backstop procurement mechanisms whereby the CAISO enters into contract to address the shortfall in order to maintain electric system reliability. CAISO backstop procurement had been on the decline but in the fall of 2017, CAISO contracted for more than 1,500 megawatts of natural gas fired generation from five different plants. This is notice that RA is not working. (*Id.* at p. 4.)

The legislative history concluded that "[t]he expansion of the DA program called for in [SB 237] may be premature given the CPUC's warning that they observe similar circumstances in the electricity market as they observed before the energy crisis of 2001." (Assem. Floor Analysis., com. on Sen. Bill No. 237 (2017-2018 Reg. Sess.) August 24, 2018, pp. 3-4.)

Both the legislative history and the plain reading of section 380 and section 365.1 are relevant here. As discussed above with respect to CalCCA's application for rehearing, in interpreting a statute, the "fundamental task … is to determine the Legislature's intent so as to effectuate the law's purpose." (*Coalition of Concerned Communities, Inc. v. City of Los Angeles*, *supra*, 34 Cal.4th at p. 737.) "Fundamental rules of statutory interpretation require that a statute be read as a whole, and its various parts harmonized so as to give effect to legislative intent. Whenever possible, effect

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should be given to every word, phrase, and clause so that no part or provision will be useless or meaningless. [Citations.]" (*Smith v. Regents of University of California*, *supra*, 58 Cal.App.3d at p. 403.) "Thus, when two codes are to be construed, they must be regarded as blending into each other and forming a single statute." (*State Dept. of Public Health v. Superior Court*, *supra*, 60 Cal.4th at p. 955 [internal citations and quotation marks omitted].)

Also as previously discussed, "[a]n administrative agency is not limited to the exact provisions of a statute in adopting regulations to enforce its mandate… [and] the absence of any specific [statutory] provisions regarding the regulation of [an issue] does not mean that such a regulation exceeds statutory authority. ... [Citations.] [The administrative agency] is authorized to 'fill up the details' of the statutory scheme. [Citations.]" (*Wendz v. California Department of Education* (2023) 93 Cal.App.5th 607, 623.) That is, "where power is given to perform an act, the authority to employ all necessary means to accomplish the end is always one of the implications of the law. [Citations.]" (*Ibid*.) And, section 701 empowers us to "do all things, whether specifically designated in [the Public Utilities Act] or in addition thereto, which are necessary and convenient' in the exercise of its jurisdiction" over public utilities. (*San Diego Gas & Electric Co. v. Superior Court*, *supra*, 13 Cal.4th at p. 915.)

The purpose of section 365.1 is a responsible approach to Direct Access, mindful of resource adequacy and reliability. Section 380 is unequivocal in our authority over resource adequacy while the legislative history of section 365.1 demonstrates keen awareness of California's reliability issues. The RA Deficiency Rule is, as discussed with respect to CalCCA's rehearing application, promulgated under our RA authority, not our jurisdiction over ESPs. Thus, we are enabled with "the authority to employ all necessary means to accomplish the end is always one of the implications of the law." (*Wendz*, *supra*, 93 Cal.App.5th at 622.)

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2. Discrimination pursuant to Public Utilities Code section 380.

ESP Parties argue that the RA Deficiency Rule discriminates against ESPs in violation of sections 380(e) and 365.1(c)(1). (ESP Parties Rehg. App., pp. 7-10.) We explained that "[t]he Public Utilities Code creates a variety of distinctions between different classes of LSEs," and lists IOUs are one example, given their role as the Providers of Last resort (POLR) whereas CCAs and ESPs are "permitted to return their customers." (Decision, p. 39.)

ESP Parties argue that the RA Deficiency Rule "treats various types of LSEs in radically different ways for deficiencies in RA compliance." (ESP Parties Rehg. App., p. 8.) But that is not accurate. We are treating all LSEs the same pursuant to section 380 by requiring that all LSEs comply with their RA requirements. If LSEs fail to comply, they are subject to the RA citation program and, if they are seeking to expand operations or take on new load, they are prevented from doing so. The perceived differences cited by ESP Parties are, as the Decision explains, due to the entities' legal distinctions. By their nature, ESPs, CCAs, and IOUs are subject to different requirements, procedures, and operations. For example, we ordered "incremental excess resources" procurement for IOUs in 2021, 2022, and 2023 in D.21-03-056 and D.21-12-015 to be incremental to, and in excess of, RA procurement that LSEs were required to undertake. Moreover, as a POLR, the IOUs have the obligation to serve all customers, even if ESPs or CCAs fail to do so. (Pub. Util. Code, § 387, subd. (a)(3).) However, ESP Parties do not argue that these additional requirements for the IOUs are somehow discriminatory.

Like with section 365.1, ESP Parties advocate for a very narrow interpretation of section 380. But, as discussed above, section 380 must be considered in light of the legislative intent and related statutes. The legislative intent behind section 380 is to give us broad authority to enact and implement the statutory goals behind resource adequacy. Related statutes and relevant authorities demonstrate that LSEs are

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routinely subject to different requirements as a result of their legal distinctions and obligations.

3. Section 394.25.

ESP Parties argue that the RA Deficiency Rule is grounded in section 394.25 (which sets out the Commission's authority to suspend or revoke ESP's registration under certain circumstances and pursuant to certain processes) which is in error. (ESP Parties Rehg. App., pp. 10-12.) But we do not rely on section 394.25 in enacting the RA Deficiency Rule. As discussed at length above, the Rule is based on our authority pursuant to section 380.

ESP Parties argue that the Decision makes "an oblique reference to the Commission's authority under section 394.25" when it acknowledges that "[b]oth CCA and ESP related statutes provide ways for the Commission to revoke the ability of such LSEs to operate if it shows the LSEs are unable to effectuate their primary functions of serving customer load consistent with their Commission-allocated RA obligations." (Decision, p. 115.) But ESP Parties quote the language out of context; this "oblique reference" is merely an example of our authority provided in response to the parties' comments on the Proposed Decision. (See *ibid*.) In fact, we do not cite or otherwise rely on section 394.25. As the Decision explains in the same paragraph, "[t]he Commission has statutory obligations to ensure energy reliability at just and reasonable rates and specific authority to ensure RA compliance," pursuant to section 380. (*Ibid*.)

4. Sufficiency of the record.

ESP Parties assert that Finding of Fact No. 6 is insufficient to support the adoption of the RA Deficiency Rule. (ESP Parties Rehg. App., pp. 12-14.) ESP Parties argue that we discuss "the significant pressures that LSEs are under with regard to their RA compliance obligations" and the RA Deficiency Rule "will not improve reliability." (ESP Parties Rehg. App., p. 13.) ESP Parties also cite CalCCA's argument that deficient ESPs do not cause cost shifting. (ESP Parties Rehg. App., p. 14.)

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First, as discussed above with regard to CalCCA's rehearing application, the evidence in the record established our and CAISO's concerns with grid reliability in light of the recent and repeated heat events. The record also established that multiple LSEs were repeatedly RA deficient. The record also demonstrated that we have recommended against expansion of Direct Access due to its reliability concerns. Nor do ESP Parties dispute our reliability concerns and findings.

Second, to the extent that ESP Parties argue that the record does not demonstrate that the RA Deficiency Rule would "enhance grid reliability" (ESP Parties Rehg. App., p. 13), they misunderstand the purpose of the Rule. As we stated, the purpose is to prevent LSEs who are already unable to procure sufficient capacity to meet their RA requirements from expanding further, again failing to procure for more customers, and, through these failures, further jeopardizing grid reliability and undermining the purpose of effective PRM. (See Decision, pp. 31, 36-38.)

Third, ESP Parties assert that "[i]f RA deficiencies are being driven at least in part by a shortage of RA capacity, then those RA capacity shortages (and the resulting deficiencies) will continue to occur regardless of whether load migrates to a new LSE or remains with the current LSE." (ESP Parties Rehg. App., p. 14.) This argument is purely speculatory and ignores the additional requirements that IOUs are subject to as POLR, for example, or that only some ESPs are continually deficient.

Finally, as discussed with respect to CalCCA's objection to Finding of Fact No. 6, when a CCA (or any LSE) underprocures, excess procurement must be used to backfill the capacity not provided by the deficiencies. The deficient CCAs avoid paying for the RA resources and, instead, rely on other LSEs to provide reliability capacity that the CCAs should have acquired directly. Thus, when a CCA fails to procure for its own customers, this results in "leaning" on the excess procurement that is paid for by all customers and, instead of supplying the full intended benefit of an additional buffer of reliability accruable to all customers, results in partial subsidy to the deficient CCA.

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C. Joint Parties' application for rehearing.

1. Conflict between D.23-06-029 and D.16-09-056.

Joint Parties claim throughout their application for rehearing that the Decision erred by preferring IOU DR programs, in violation of D.16-09-056, which set forth a principle of competitive parity between IOU and third-party DR. Joint Parties also generally argue that Federal Power Act sections 205 and 206 prohibit undue discrimination or preferences in organized electricity markets, citing Federal Energy Regulatory Commission (FERC) Order 719. (Joint Parties' Rehg. App., p. 3.)

These claims lack the specificity required by Rule 16.1(c). To the extent that specific claims of unfair playing field and discriminatory competition are raised regarding the issues discussed below, they are addressed herein. Generally, however, the claims that the Decision is unlawfully continuing to favor IOU DR lack specific allegations as to how we violated any rule or law, making it impossible for the Commission to correct any legal error, which is the purpose of an application for rehearing.

To the extent particular adjustments to DR programs are alleged to violate the principle of competitive parity, several of those involve our policy decisions which are made pursuant both to our statutory responsibilities under Public Utilities Code section 380.5 to ensure demand response supplies ratepayer benefits and to prior decisions, including D.16-09-056. That decision adopted not only the principle of competitive parity cited by Joint Parties but also the principle that "demand response shall evolve to complement the continuous changing needs of the grid." (D.16-09-056, pp. 97-98, OP 8.) By ensuring that ratepayers do not pay twice for third-party DR and by adjusting DR programs as necessary based on the record to ensure grid needs are met by demand response products, the Commission is complying with statutory and decisional law. Because Joint Parties have not specified how we contravened D.16-09-056 or FERC Order 719 or otherwise abused our discretion in making these policy adjustments, rehearing should be denied as to these claims.

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2. Clarification of policy.

Joint Parties assert that RDRR cannot be used prior to the calling of a grid emergency. (Joint Parties' Rehg. App., p. 11.) This position is not supported by prior decisions, which state that RDRR should be used prior to the CAISO contacting neighboring balancing authorities for energy or capacity, to help avoid a system emergency. (See D.10-06-034, p. 2.) Moreover, due to CAISO changing its operating protocols from Alert, Warning, Emergency (AWE protocols) to NERC protocols, which include Energy Emergency Alert (EEA) Watch, EEA I, EEA II, and EEA III, we clarified in D.23-06-029 how RDRR, as an RA resource, should be dispatched before an actual system emergency. Due to minor differences between AWE and NERC protocols, leading to a situation where, under the NERC protocols, CAISO has not been dispatching RDRR RA resources before a system emergency. This is contrary to the intent of earlier decisions, which require that RDRR should be dispatched to help avoid emergency situations by being called during times of grid stress that do not rise to actual system emergencies. Moreover, all three decisions, D.23-06-029, D.18-11-029 and D.10-06-034, consistently make the important policy determination that ratepayers should not have to pay twice for the same resource, which Joint Parties fail to address in the application for rehearing.

Joint Parties argue that the Commission "reverses the present limitation on using RDRR as an RA resource during system emergencies only, defined by a CAISO Energy Alert (EEA) 2, and instead now directs that the CAISO "should be allowed to use RDRR, as an RA resource, for economic or exceptional dispatch upon the declaration of a day-of [Energy Emergency Alert ("EEA") Watch (or when a day-ahead EEA Watch persists in the day-of)." (Joint Parties Rehg. App., pp. 2-3.) Joint Parties claim that D.23-06-029 is thus inconsistent with both D.10-06-034 and D.18-11-029. (Joint Parties' Rehg. App., p. 11.) Therefore, Joint Parties allege that what the Commission has characterized as a "clarification" of existing policy is in fact a modification of the 2010 and 2018 decisions and thus requires findings of fact and ordering paragraphs and should not be made effective immediately. (Joint Parties' Rehg. App., p. 2.) Joint Parties allege that "[n]ot

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only does this "clarification" fail to meet required legal standards for Commission decisions, but, if enforced by the Commission, wrongly results in eliminating RDRR as an emergency resource, which will lead to them being triggered sooner than they were intended to be, rendering them unavailable during actual emergencies." (Joint Parties' Rehg. App., p. 3.).

We are not persuaded by Joint Parties' arguments. As we clarified in D.23-06-029, the overriding objective for RDRR is that it should be available to mitigate or avoid an emergency grid reliability situation. We noted that prior decisions had the same goal. D.10-06-034 adopted a settlement in which CAISO enabled RDRR bids to be available for dispatch before CAISO emergency measures are taken. D.18-11-029 affirmed the 2010 decision and clarified the CAISO's dispatch order under previous protocols. (D.23-06-029, p. 95.) In the instant Decision, we again clarified the CAISO's dispatch order, which was necessitated by CAISO's change from AWE protocols to the NERC operating procedures. We clarified that CAISO should be able to use RDRR, as an RA resource, for economic or exceptional dispatch when CAISO declares a day-of EEA Watch (or when a day-ahead EEA Watch persists in the day-of.) As we noted, aligning the trigger to a day-of EEA Watch as a condition of RA-eligibility to reflect the NERC protocols is supported by CAISO. (D.23-06-029, p. 96.) While CAISO recognizes this approach may result in more frequent dispatch of RDRR than in the past, it asserts that DR use limitations will continue to be respected.[4] As we emphasized, if the RDRR trigger were later in the EEA sequence, "RDRR would only be enabled to mitigate emergency conditions, not to help prevent them, which is why these resources receive RA payments." (D.23-06-029, p. 97.)

Adjusting the trigger in view of CAISO's new operating procedures under NERC protocols is thus a clarification and not a modification as shown by review of the two prior decisions. As D.10-06-034 states, the reliability-triggered demand response program can be triggered prior before the CAISO canvasses neighboring balancing

[4] CAISO Opening Comments, p. 10.

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authorities for energy or capacity. (D.10-06-034, p. 2.) While Joint Parties acknowledge this, they assert without citation that the conditions triggering an EEA Watch do not approach this degree of urgency. (Joint Parties' Rehg. App., p. 11.) In D.23-06-029, we reasonably determined based on the record before us when the trigger should occur, consistent with past decisions. Further, as we observed in D.18-11-029, the intent of D.10-06-034 was to "eliminate the anomalous treatment whereby emergency-triggered demand response counts for resource adequacy yet, unlike all other power that counts for resource adequacy, the CAISO currently procures costly exceptional dispatch energy or capacity before using this energy resource, a practice that has led to charges that ratepayers pay twice for this power." (D.18-06-037, pp. 36-37.)

Joint Parties make several additional vague assertions of legal error regarding the clarification. For example, Joint Parties allege DR cannot contribute to grid reliability "when pushed to dispatch outside their operational limitations, a condition FERC recognized in Order 2222" and which Joint Parties allege was ignored by the Commission. (Joint Parties Rehg. App., p. 20.) Joint Parties do not explain how the Commission's clarification will push DR to dispatch outside of their operational limitations. Also, no further explanation as to what condition FERC is recognizing nor page citation to the FERC order is given. Therefore, this argument fails to meet the requirements of Rule 16.1 that applicants for rehearing specify their claims of legal error so that the Commission may address them. In addition, since CAISO supports this clarification and has stated it will respect DR's operational limitations, it can be assumed that CAISO views the clarification as consistent with the FERC order and does not see an operational problem with dispatching DR during the period where CAISO declares an EEA Watch in the day-ahead or day-of timeframe when CAISO forecasts "one or more hours may be energy deficient."[5]

Because we are clarifying an existing policy, it is appropriate to make it effective immediately. Joint Parties' arguments to the contrary lack merit and are denied.

[5] CAISO Operating Procedure 4410, p. 7; see also CAISO's Opening Comments, p. 10.

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3. Commission discretion and authority.

Energy Division's proposal pointed out that no other distribution-connected resources receive a transmission adder, so there is an inconsistency between the treatment of DR and other resources at this time. With regard specifically to the PRM adder, Energy Division asserts that while the current PRM adder accounts for forecast error and forced outages, DR does not lower either factor because if the CAISO does not procure to meet load, there would be no DR load to curtail. (D.23-06-029, pp. 98-99.) Energy Division additionally notes that the CAISO has stated that there is no evidence that DR lowers the system forecast error or the system average forced outage rate.[6]

Energy Division's view is that the administrative burden of "grossing up" RA filings to account for these adders is not currently outweighed by the relatively small ratio of MW that are being processed, and that these related MW do not add to or further support reliability. Energy Division therefore proposes removing the TLF and PRM adders for DR resources. (D.23-06-029, pp. 98-99.)

The Decision agrees with Energy Division and eliminates the TLF and PRM adders to DR resources. We found that there was a significant administrative burden on Energy Division Staff associated with applying the TLF and PRM adders to DR resources. As we noted, the record does not demonstrate that this administrative burden for both the TLF and PRM adders is outweighed by the potential value of the relatively small amount of MW associated with the adders. (D.23-06-029, pp. 99, 102.) Further, according to CAISO's Department of Market Monitoring (DMM), its reports show that PRM and TLF adders "have resulted in RA values that overestimate the availability of DR capacity." Thus, DMM states, removing the adders "is necessary to reduce the extent to which DR capacity is used to meet RA requirements but is then not available under critical system conditions."[7]

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[6] R.19-11-009, *Track 4 Proposals of the CAISO* (January 28, 2021), p. 9.

[7] DMM Reply Comments, p. 2.

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Joint Parties allege that D.23-06-029 erred by eliminating the TLF Adder because the administrative burden to Energy Division is not outweighed "by the relatively small ratio of MW that are being processed." (Joint Parties' Rehg. App., p. 3.) Joint Parties argues that the Decision does not describe how much of an administrative burden the TLF adder represents and that the Commission cannot credibly make this determination. (*Id.* at p. 13.) Joint Parties argue that demand-based resources, by cutting demand, also reduce transmission line losses. (*Id.* at p. 3.) Further, Joint Parties argue that removing the TLF adder will put DR resources at a competitive disadvantage to generation resources, "which are not required to account for TLF when selling capacity in the CAISO market." (*Ibid*.) Joint Parties also allege that the Decision erred in removing the PRM adder. (*Ibid.*)

We did not err in making these policy adjustments to the DR program. The Decision states, the record does not show that this administrative burden for the TLF and PRM adders "is outweighed by the potential value of the relatively small amount of MWs associated with the adders." (D.23-06-029, p. 102.) Finding of Fact 20 states that "[t]here is significant administrative burden on Energy Division Staff associated with apply the TLF and PRM adders to DR resources and a relatively small amount of MW associated with the adders." This finding is fully supported by the record. While Joint Parties contend there is almost no administrative burden to Energy Division in processing the TLF Adder because it can be a single combined adder with the Distribution Loss Factor adder (Joint Parties' Rehg. App., p. 13), they do not point to record evidence to support their argument. A party challenging a Commission's finding for lack of substantial evidence must demonstrate that, based on the evidence before the Commission, a reasonable person could not reach the same conclusion. (*The Ponderosa Telephone Co. v. Public Utilities Com.* (2019) 36 Cal.App.5th 999, 1013.)

Moreover, removal of the adders starts in 2024, giving DR providers time to decide to provide RA capacity or not based on the new terms. The Decision also noted that we may revisit the TLF adder issue, should a more streamlined process for incorporating TLF values into the CPUC and CAISO processes be identified in the

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future. (D.23-06-029, p. 102.) With respect to the PRM adder, we reasonably determined based on the record "that removal of the adder is likely to enhance reliability, particularly during stressed conditions, by removing the risk that the PRM adder over-estimates the amount of capacity available to the CAISO on high system stress days." (D.23-06-029, p. 102.)

Finally, in their application for rehearing, Joint Parties present a chart purporting to show the value of the lost DR capacity from eliminating the adders. (Joint Parties' Rehg. App., p. 15.) This chart is new evidence, not in the record of this proceeding and thus not appropriate to raise at the rehearing stage. Discontinuing the use of TLF and PRM adders for DR resources at this time, based on the record before us, is an appropriate exercise of our discretion, to help ensure ratepayer costs are reasonable. Joint Parties' claim that the Commission erred in eliminating the TLF and PRM adders is denied.

4. Proxy DR (PDR) availability requirement.

D.23-06-029 agrees with Energy Division and DMM that the Commission's DR availability requirements should help ensure that DR resources are available when needed most. We found adjustments to the existing DR availability requirements are necessary for DR to be available during the kinds of prolonged weather events experienced recently. The Decision added the requirement that DR resources must also be available during a CAISO Flex Alert, through the last day for which the CAISO has issued a Grid Warning, or the Governor's Office has issued an emergency notice. The Decision acknowledged parties' concerns that while the new additional requirements may present some operational challenges to certain DR providers, the need for limited additional availability of those resources outweighs the potential for those providers to be unable to perform. Finally, due to operational constraints of RDRR, RDRR resources were exempted from the additional requirements. (D.23-06-029, p. 106.)

Joint Parties allege that expanding DR availability will discourage participation by DR providers. (Joint Parties' Rehg. App., p. 16.) According to Joint Parties, this contradicts D.16-09-056 by "adopting a requirement which would stifle DR instead of

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"growing" it. (*Ibid.*) Moreover, increasing the frequency as to when DR providers need to be available would create confusion, uncertainty and customer fatigue. (*Id*. at p. 17.) Finally, Joint Parties allege that the expanded availability requirements "are out of step with FERC Order 2222, requiring ISOs to adopt bidding parameters to account for the physical operational characteristics of distributed energy resource (DER) aggregations." (*Id.* at p. 19.)

Aside from Joint Parties' claim that expanding availability conflicts with D.16-09-056's policy to grow DR, which is countered by the fact that the Commission must balance growing DR with its other statutory and decisional responsibilities, the claims above are not legal claims, but rather serve as a caution that the Commission may not receive as much PDR as expected. If a shortfall in PDR does occur, the Commission can further adjust these requirements as necessary. At the same time, Joint Parties fail to acknowledge that the Commission exempted RDRR from the additional requirements for operational reasons. Also, because CAISO supports expanded DR availability, it can be assumed that CAISO does not see a conflict with FERC Order 2222.

Finally, Joint Parties allege Finding of Fact 22 (adjustments are needed to existing DR availability to ensure DR is available during types of prolonged weather events experienced in recent years) and Conclusion of Law 21 (DR availability requirements should be expanded so that resources are available when most needed) do not provide a basis for supporting Ordering Paragraph (OP) 32, which contains the additional availability requirements. (Joint Parties' Rehg. App., p. 23.) Joint Parties claim that the Commission has not demonstrated how OP 32 will improve PDR availability. (*Ibid.*)

Joint Parties' claims lack merit. Joint Parties have the burden of establishing error in a Commission decision. We explained that expanding DR availability due to recent prolonged weather events will improve DR availability when it is most needed. (D.23-06-029, p. 106.) Joint Parties have not shown that the additional requirements will not provide additional PDR availability as expected. Further, the finding and conclusion as well as the rationale discussed in the Decision all support the additional requirements in

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the Ordering Paragraph. Thus, we deny Joint Parties' claims that the Commission erred in adopting expanded availability requirements.

5. Third-party DR qualifying capacity values.

Joint Parties allege that the Decision errs in derating third-party DR qualifying capacity (QC) values when IOU DR is not subject to these requirements and based on test results outside the current QC valuation process. (Joint Parties' Rehg. App., pp. 4-5.) Joint Parties cite to D.23-06-029 which orders that "test performance failures will be considered when making capacity awards to non-investor-owned utility demand response (DR) resources procured by third-party DR providers. (D.23-06-029, p. 145, OP 32.) The Decision discusses Energy Division's concern that current test levels do not show that DR resources are performing reliably. (*Id.* at p. 109.) This concern is based on 2022 test performance results, with actual performance considerably below the monthly supply plans. As we noted in the Decision at 111, "[p]erformance in the range from 25 to 50 percent of what is on the supply plans is not an acceptable level of performance." In addition, DR providers do not always submit updated filings as required when resources fall below applicable thresholds. (D.23-06-029, p. 109.)

To address these problems, Energy Division proposed derating the non-IOU DR resources' capacity corresponding to their performance during test events for a particular quarter. Thus, DR resources that consistently fail to deliver their scheduled load curtailments should have their capacity awards lowered to better reflect the actual amount of RA provided. (D.23-06-029, p. 110.) Based on the record of comments and reply comments on Energy Division's proposal before us, we agreed that incorporating test results in capacity estimates "could incentivize resources to provide accurate estimates and to perform better when dispatched" to become more reliable RA resources. (*Id.* at p. 111.)

Joint Parties allege inconsistency with D.16-09-056 and discrimination since unlike third-party DR, which must file supply plans, (and thus have their QC derated if they fail to meet those plans), IOU DR is not required to be on a supply plan, and "thus, IOUs have the freedom to tailor their bids to reflect the capability of their DR sources on

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a particular day, which does not need to reflect the QC value awarded it by Energy Division." (Joint Parties' Rehg. App., p. 17.)

Joint Parties fail to recognize the Commission's responsibility pursuant to section 380.5 to ensure DR resources deliver the expected results and provide ratepayer benefits. Since there are differences in calculating IOUs' DR QC and non-IOU third-party QC for RA purposes, Joint Parties have not shown a basis for claiming that the Commission must apply the same standards to both in considering whether to derate third-party DR. Further, while the Commission acknowledged parties' concerns regarding different treatment of DR resources managed by IOUs versus resources managed by third parties, there was evidence to show that "IOU DR resources appear to have met a majority of the scheduled load reductions." (D.23-06-029, p. 111.)

Joint Parties allege that Finding of Fact 24 (third-party DR "is not performing reliably in comparison to monthly supply plans") and Conclusion of Law 23 (third-party DR "QC should be derated based on performance during test events relative to their QC values" are overly broad to support OP 32, which derates third-party DR QC based on test performance failures (D.23-06-029, p. 146). Also, Joint Parties again claim that this provision fails to treat IOU and third-party DR providers equally. These claims lack merit. First, FOF 24 and COL 12 are based on the record and fully support OP 32. Second, as explained above, the factual differences in IOU and third-party DR require us to treat them differently. There is no inconsistency with D.16-09-056.

Joint Parties also claim derating QC based on test results earlier in 2023, before the issuance of this decision, result in retroactive sanctions. (Joint Parties' Rehg. App., p. 5.) Joint Parties' position appears to be that their prior poor performance on test events should be ignored because they did not have notice that their test event performance could impact their future ACT award. Joint Parties are mistaken. Joint Parties had a performance obligation when they were tested, but it had no consequences if they failed to meet their existing obligation prior to D.23-06-029. However, implicit in the Commission's ability to require quarterly performance testing is the authority to set and enforce performance standards and results to ensure ratepayers receive the value they are

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paying for. Otherwise, the performance testing would be pointless. Moreover, the Commission has not only the authority but the responsibility to derate capacity for DR providers under section 380.5(a)(2). We would not be complying with section 380.5 if we did not make necessary adjustments to various aspects of the DR program to ensure ratepayer benefits.

Finally, Joint Parties' claim that derating DR QC is inconsistent with D.16-09-056 (Joint Parties' Rehg. App., p.17) does not comply with the requirements of Rule 16.1, since they do not specify the inconsistency or cite to a specific page. The Commission is not required to hunt through a lengthy decision to try to ascertain the legal error.

Derating of DR QC has not been shown to be discriminatory nor does it constitute a retroactive sanction for third-party DR. We made a policy adjustment based on the record, in furtherance of our statutory duty and acted within our discretion. Therefore, Joint Parties' claim of legal error regarding derating of QC lacks merit and is denied.

6. Motion for partial stay.

Joint Parties filed a Motion for Partial Stay of D.23-06-029 pending disposition of the application for rehearing. Joint Parties claim that the partial stay should be granted or else they will be irreparably harmed by the Decision. Since we deny Joint Parties' application for rehearing, the motion for partial stay of the Decision is moot and is denied.

7. Request for oral argument.

The Joint Parties requested oral argument. (Joint Parties' Rehg. App., pp. 26-27.) Under Rule 16.3, oral argument is not necessary as it would not materially assist the Commission in resolving this case and the request is therefore denied.

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III. CONCLUSION

For above reasons, we deny rehearing of the Decision.

THEREFORE, IT IS ORDERED that:

1. Rehearing of D.23-06-029 is denied.
2. Joint Parties' Motion for Partial Stay of D.23-06-029 is denied.
3. This proceeding remains open.

The order is effective today.

Dated December 14, 2023, at San Francisco, California.

ALICE REYNOLDS
President
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
Commissioners

Commissioner Genevieve Shiroma, being necessarily absent, did not participate.

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