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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	R.19-03-009

PETITION FOR MODIFICATION OF DECISION 21-06-033 BY THE ALLIANCE FOR RETAIL ENERGY MARKETS, CALIFORNIA COALITION OF LARGE ENERGY USERS, DIRECT ACCESS CUSTOMER COALITION, REGENTS OF THE UNIVERSITY OF CALIFORNIA, SHELL ENERGY NORTH AMERICA (US), L.P. AND WESTERN POWER TRADING FORUM

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And on behalf of the Competition Parties

April 6, 2026

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In accordance with the provisions of Section 16.4 of the Commission's Rules of Practice and Procedure, this petition for modification (Petition) is filed by the Alliance for Retail Energy Markets,[1] California Coalition of Large Energy Users (CLEU),[2] Direct Access Customer Coalition (DACC),[3] Regents of the University of California (UC), Shell Energy North America (US), L.P., (Shell) and the Western Power Trading Forum (WPTF)[4] (collectively, the Competition Parties) with regard to Decision (D.) 21-06-033 (the DA Decision), issued on June 29, 2021.

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[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers (ESPs) that are active in the California's direct access ("DA") market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] CPUC Rule 16.4(e) provides that, "If the petitioner was not a party to the proceeding in which the decision proposed to be modified was issued, the petition must state specifically how the petitioner is affected by the decision and why the petitioner did not participate in the proceeding earlier." CLEU was recently formed and thus could not have participated in R.19-03-009. CLEU's members rank among the largest electricity ratepayers in the state, collectively consuming hundreds of millions of kilowatt-hours annually. To the extent permitted under the current cap, CLEU members utilize direct access, would like the opportunity to utilize it more freely, but are constrained by the Commission's earlier decision not to reopen direct access.

[3] DACC is a regulatory advocacy group comprised of educational, commercial and industrial customers that use direct access for all or part of their demand.

[4] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, the parties hereto have authorized counsel to file this document on their behalf.

Rule 16.4(b) provides in part, as follows:

> A petition for modification of a Commission decision must concisely state the justification for the requested relief and must propose specific wording to carry out all requested modifications to the decision. Any factual allegations must be supported with specific citations to the record in the proceeding or to matters that may be officially noticed. Allegations of new or changed facts must be supported by an appropriate declaration or affidavit.

This Petition complies with those requirements.

Rule 16.4(d) provides

> Except as provided in this subsection, a petition for modification must be filed and served within one year of the effective date of the decision proposed to be modified. If more than one year has elapsed, the petition must also explain why the petition could not have been presented within one year of the effective date of the decision.

As more than one year has elapsed since the effective date of the DA Decision, the Competition Parties comply with the Rule 16.4(d) requirement in the succeeding section of this petition and the attached declaration of counsel.

I. <u>THIS PETITION COULD NOT HAVE BEEN FILED WITHIN ONE YEAR OF THE DECISION.</u>

This Petition is filed as a direct result of Commission Decision D.26-02-057 (IRP Decision). As the effective date of that decision is March 5, 2026, this Petition could not have been presented within one year of the effective date of the DA Decision, per Rule 16.4(d). Therefore, the Competition Parties explain herein why this Petition could not have been filed earlier.

As background, subsequent to the issuance of the DA Decision, the Commission has engaged in extensive efforts in its Integrated Resource Planning (IRP) proceedings in Rulemakings

R.20-05-003[5] and R.25-06-019.[6] The primary ongoing requirements for the IRP process are contained in Public Utilities Code Sections 454.51 and 454.52, which require the Commission to identify a diverse and balanced portfolio to ensure a reliable electric supply that can integrated renewable energy in a cost-effective manner. In addition to their focus on reliability, these proceedings have also been the primary venue for policy strategy and implementation to achieve the goals of Senate Bill (SB) 350 (Stats. 2015, Ch. 547) related to IRP and the environmental goals of SB 100 (Stats. 2018, Ch. 312) for reductions of greenhouse gas (GHG) emissions from the electricity sector in California.

Further, AB 1373 (Chapter 367 of 2023) modified the IRP statutes, specifically Section 454.51, to clarify the Commission's ability to order ESPs to pursue procurement of long-term contracts. This legislation was passed more than one year after the DA Decision. The bill addressed many of the CPUC's concerns with its ability to order ESPs to pursue long term procurement. Essentially, it equalized the treatment of LSEs across all LSE types concerning the procurement of both resource adequacy (RA) and integrated resource planning.

Most recently, in R.25-06-019, the Commission issued the IRP Decision, which was also more than one year after the Decision. The Decision was approved at the Commission's February 26, 2026, voting meeting and was issued on March 5, 2026. Concurrently herewith, certain members of the Competition Parties[7] are filing an application for rehearing of the 2026 IRP Decision (Rehearing Application). The rehearing application alleges that in approving and issuing

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[5] Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes, Filing Date: May 7, 2020.

[6] Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes, Filing Date: June 26, 2025.

[7] DACC and CLEU were not a party to the IRP proceeding and thus do not have standing to join the Rehearing Application.

the IRP Decision, the Commission "acted without, or in excess of, its powers or jurisdiction" within the meaning of Section 1757(a)(1) and "has not proceeded in the manner required by law" within the meaning of Public Utilities Code section 1757(a)(2). Further, it states that the IRP Decision "is not supported by the findings" within the meaning of Section 1757(a)(3).

The Rehearing Application alleges that the IRP Decision will cause inappropriate cost shifting to DA customers, counter to the requirements of Public Utilities Code Sections 397, 365.2, 366.2(d)(1), 366.3 and 454.52.[8] The cost shift occurs because the IRP Decision (despite expressly identifying anticipated new load growth, including data center and electric vehicle charging load as principle drivers of the need for incremental procurement) goes on to order procurement of new resources to meet "reliability" needs and simultaneously allocates procurement responsibility of this procurement to all LSEs—including all ESPs. However, due to the cap on California's Direct Access (DA) program, ESPs will be unable to serve this new load.

The DA cap, which is a volumetric cap specified in the terms of kilowatt-hours, will prevent ESPs from serving additional load growth regardless of broader customer demand. The recent IRP Decision thus requires ESPs and their respective DA customers to bear the procurement costs associated with load growth outside of the DA market, thereby causing the precise form of improper cost shifting the Public Utilities Code prohibits.

This statutory mismatch is not merely theoretical; it has immediate and concrete consequences for existing DA customers and for the competitive suppliers that are barred from serving the load growth driving the Decision's procurement mandate due to the long-standing cap on DA participation. The cap has been reached for two of the three investor-owned utilities

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[8] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

(IOUs)'[9] service territories, and only limited cap space remains in the third. As a result, ESPs cannot enroll new customers in most of the state and cannot meaningfully serve new large loads, including data centers, hospitals, research centers, or electric vehicle charging stations. Even so, the IRP Decision requires ESPs to procure capacity for that load. The effect is straightforward: existing DA customers, including DACC members, will bear procurement costs attributable to load that ESPs are not legally permitted to serve, while those costs instead should be borne within the service territories of the LSEs that are actually capable of taking on that new demand.

The Rehearing Application recommends that the simplest remedy would be for the Commission to modify Decision 21-06-033 and issue a recommendation to the Legislature asking it to permit all non-residential customers to freely select the supplier of their choice. If the Legislature acts within the 2026 legislative session, ESPs will fairly have the ability to compete to serve the new load upon which the IRP Decision is premised. However, if the Legislature does not so act by the conclusion of the 2026 Legislative Session, the Commission should reallocate the Decision's procurement obligations so they are consistent with Section 397, accounting for the cap on DA and ESP load constraints.

Herein, this Petition explains how and why the Commission should issue a new recommendation to the Legislature that it should remove the cap on DA.

As explained above, this Petition for Modification could not have been filed within one year of the DA Decision because the total impact of the decision was not clear until recently. Modification is now warranted by subsequent actions by the Commission and the Legislature: the recent issuance of the IRP Decision and the concrete inequity it imposes on DACC members and other DA customers served by ESPs. Under the IRP Decision, ESPs have been allocated a

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[9] The cap has been reached in PG&E and SDG&E territory. SCE has limited cap space available.

proportional share of 6 gigawatts (GW)[10] of significant new "perfect" renewable capacity (measured as NQC) procurement required to address anticipated load growth from data centers and electric vehicle charging. We estimate that the actual procurement required, based on ELCC accounting, will be *at least* four times the ordered "perfect" capacity. Yet ESPs are not permitted to serve that load because of the statutory cap on DA participation and this Commission's 2021 recommendation to the Legislature in the DA Decision.

This new, recent remarkable IRP Decision will significantly and negatively impact DA customers by imposing on their ESP suppliers procurement obligations that exceed the ESP's load they are legally permitted to serve under the DA cap. As a result, this Petition could not have been presented within one year of the effective date of the DA Decision per Rule 16.4(d)

However, if the Commission was to modify the DA Decision and send a positive recommendation to the Legislature, providing guidance to the Legislature to remove the cap on DA, legislation to lift the cap could in alignment with the timing for ESPs to comply with the procurement obligations allocated to them in this IRP Decision. This Petition for Modification goes on to explain the reasons why it would be appropriate and reasonable for the Commission to act in the manner requested.

Further, as required by Rule 16.4(b), the Competition Parties propose specific wording to carry out all requested modifications to the DA Decision. Allegations of new or changed facts are also supported by an appropriate declaration attached to the Petition for Modification. The Competition Parties provide the specific modifications requested to D.21-06-033 in Appendix A.

[10] The new procurement required is 2,000 megawatts (MW) of net qualifying capacity (NQC) by 2030, another 2,000 MW NQC, by 2031, and an additional 2,000 MW NQC by 2032.

II. PETITION FOR MODIFICATION.

The Competition Parties respectfully request that the Commission modify the DA Decision and send the Legislature a recommendation that the cap on DA be lifted. In support of this request, the Competition Parties offer the following facts in support of modifying the DA Decision.

A. The Initial September 2020 Staff Report Assessment Recommended Reopening DA

In the fall of 2020, Administrative Law Judge (ALJ) Jeanne M. McKinney issued a ruling[11] inviting comment on the Staff Report Providing Recommendations on the Schedule to Reopen Direct Access (the Staff Direct Access Report). That report stated Staff's belief that DA could be reopened subject to ESPs' demonstrated compliance with the following obligations:[12]

- ESPs submit robust, transparent Integrated Resource Planning (IRP) filings and meet all procurement requirements pursuant to Decision (D.) 19-11-016;
- ESPs meet their Renewables Procurement Standards (RPS) obligations for the 2021-2024 compliance period[13]; and
- ESPs comply with all Resource Adequacy (RA) requirements including multi-year local, year ahead flexible and system, and month ahead system and flexible obligations.

Each of these obligations have been met by ESPs, collectively. Compliance with subsequent procurement obligations is yet to be determined, as discussed above.

Staff further recommended that the Commission set an initial re-opening schedule for DA in increments equal to 10 percent of eligible non-residential load per year. However, the DA Decision essentially ignored Staff's recommendation because, due to what the Competition Parties understood to be pressure from now former Commissioners, the Staff Report was subsequently

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[11] September 28, 2020, *Ruling Inviting Comments On The Staff Report Providing Recommendations On The Schedule To Reopen Direct Access*.

[12] ESPs have met these requirements. For discussion of IRP procurement and RA, see Section IIC. For discussion of IRP long term planning, see Section IID. For discussion of RPS standards, see Section IIE.

[13] *See,* CPUC, *2025 California Renewables Portfolio Standard Annual Report*, November 2025, page 23.

revised significantly to recommend against reopening DA. The final DA Decision then recommended telling the Legislature should not be reopened for two primary reasons.

First, it claimed that "While ESPs have recently begun to secure contracts for generation resources; ESPs' lack of track record in building new generation resources, system reliability would be at increased risk if ESPs were to serve a significant portion of the states' load. Except for a few notable exceptions, most ESPs' procurement practice is to primarily rely on CAISO system power to meet all energy needs beyond their RPS requirements. The GHG emissions factor for CAISO system power is slightly higher than gas generation."[14] As discussed in Section IID below, ESPs are held to the same RA and GHG reduction requirements as other LSEs and changes to system power accounting will reduce supposed procurement disparities among LSEs.

ESPs cannot just "rely on CAISO system power" to meet their needs for RA, they must hold RA contracts like everyone else, and must also contract for local capacity or it must be contracted for on their behalf. Given that RPS requirements have increased significantly year-over-year, the proportion of total procurement represented by long-term RPS contracts is significant. Furthermore, in 2021 and 2022 the Commission issued additional "mid-term reliability" procurement orders for new capacity,[15] which created additional long-term contracting requirements for all ESPs. In other words, the conditions that the DA Decision seemed to rest upon simply do not exist and have not for many years.

Secondly, the DA Decision stated that, "If past procurement indicates future outcomes, then load migration from IOUs or CCAs to ESPs may lead a net decline in RPS procurement,

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[14] DA Decision, at p. 11.

[15] *See*, D.21-06-035, *Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026)* and D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) And Transmitting Electric Resource Portfolios To California Independent System Operator For 2023-2024 Transmission Planning Process*.

relative to maintaining the current cap on Direct Access, which may increase GHG emissions and increase criteria air pollutants and toxic air contaminants."[16] As discussed in Section IIE below, ESPs are also subject to the same requirements for RPS and criteria air pollutants as other LSEs, and ESPs are successfully meeting RPS requirements. The logic of this element of the DA Decision was, and still is, flawed and inconsistent with ESPs legal obligations.

Thus, these concerns have been addressed by both the Commission and by ESPs, thereby eliminating the factors that led to the Commission's recommendation in the DA Decision.

B. The Suspension of DA and the DA Cap Are an Outdated Vestige of the 2000-2001 Energy Crisis

The California energy crisis that occurred between 2000 and 2001, was characterized by market manipulation, supply shortages, and rolling blackouts. It directly led to the suspension of Direct Access, via Assembly Bill 1X in 2001. The bill was designed to prevent further customer migration from the investor-owned utilities (IOUs) so that the IOUs could stabilize their load and procurement obligations. Limited direct access for non-residential users was slowly reopened years later under Senate Bill 695 (2009) and expanded by Senate Bill 237 (2018).

In other words, events of over a quarter of a century ago were the cause of DA suspension and the cap. The causative factor to those events have long since been addressed by both the Legislature and the Commission in multiple ways. For example, the Legislature's enactment of the Resource Adequacy (RA), Renewable Portfolio Standard (RPS), and IRP statutes established a comprehensive framework under which ESPs are now required to make meaningful contributions to system reliability and the State's clean energy objectives in a fair and equitable manner, thereby addressing the very concerns that have been used justify the ongoing suspension

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[16] *Ibid.*

of Direct Access and retention of the DA load cap long after they have served their intended purposes.

The IRP process is one such way, as the Commission has imposed strict planning and reporting requirements regarding the procurement activities of all LSEs, including ESPs. The Renewable Portfolio Standard (RPS) has been implemented for all LSEs for many years, requiring the procurement of renewable resources designed to help the State meet its ambitious climate goals. The same can be said for the Greenhouse Gas (GHG) requirements that are also imposed on ESPs and all LSEs. Moreover, the Commission also imposed significantly stricter standards for parties to register as ESPs.[17]

In other words, the rationale that led to the original suspension of DA has long since been addressed by both the Legislature and this Commission. The continued suspension of DA is an anachronism that is both unnecessary and unreasonable. Moreover, its elimination will contribute to a healthier, more competitive California electricity market.

Retail competition in electric markets is beneficial because it lowers costs, drives innovation, and improves customer service by encouraging providers to compete for market share. It empowers consumers to choose from diverse, cleaner energy plans and encourages efficiency through market-driven incentives rather than, or in addition to, regulation. It forces efficiencies, encourages the adoption of cleaner energy, shifts investment risks from consumers to private investors and permits the development of innovative rate offerings. For example, ESPs have found that offering hourly dynamic rates indexed to the CAISO day-ahead market is an offering popular among DA customers to allow them to better manage their load profiles. Furthermore, competitive

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[17] *See,* Decision D.03-12-015.

markets often lead to lower wholesale electricity prices, with competitive retail markets showing smaller price increases compared to monopoly states.

C. The DA Program Is Ideal for Serving New Large Loads

Since the time of the DA Decision in 2021, the outlook for load growth in California has fundamentally changed from one of incremental growth to rapid load growth. The largest drivers of load growth according to the California Energy Commission's California Energy Demand Integrated Energy Policy Report (IEPR Forecast) are the anticipated needs to serve electric vehicle charging, new large data centers and "additional fuel switching."[18] The tables below compare the amount of load growth in the 2021 IEPR Forecast to the most recent 2025 IEPR Forecast. As the tables shows, the IEPR Forecast now predicts energy consumption in the CAISO balancing authority to grow by over 40% in the next ten years.

2025 IEPR Update

	2026	2036	Ten-Year Load Growth
CAISO Total Energy to Serve Load (GWh)	215,318	304,628	41.5%

2021 IEPR-Mid Baseline Forecast (Dated Feb 2022)

	2021	2031	Ten-Year Load Growth
CAISO Total Energy to Serve Load (GWh)	213,408	237,741	11.4%

The DA Program is well-suited to meet the needs of new large commercial loads, such as data centers. Under this program, a data center customer could obtain service from an ESP under a dedicated contract that is negotiated between the customer and the ESP. Such arrangements would be a win-win situation for large load customers and the rest of the state. New large loads get the advantage of flexibility in contracting that can meet their needs, including providing the

[18] "Energy Commission 2025 IEPR Forecast, Updated Results," Presented to the Demand Analysis Working Group January 5, 2026.

customer's desired level of green power attributes,[19] while other customers bear no risk of generation rate increases or stranded costs.

However, because the DA Program is capped, ESPs will be hindered from serving any new large load customers. The state will then be forced to attempt to create an entirely new program or suite of policies to attempt to limit the risk of rate increases due to new large loads. This is wholly unnecessary as the DA Program is already well-suited to serve this function and has been in place for many years. Furthermore, it would require very limited administrative effort by the state to lift the cap as this Petition seeks to accomplish. Lifting the DA cap would have the effect of helping to insulate residential and small business customers from the generation costs associated with serving new large load.

D. Reliability Would No Longer Be at Risk If DA Was Reopened.

The DA Decision stated that "the Commission cannot find that expansion of Direct Access will ensure electric system reliability" citing "existing uncertainties around procurement planning raised by the August 2020 energy shortage and the February 2021 power crisis in Texas" as specific concerns that led the Commission not to recommend lifting the DA cap.[20] The reliability of CAISO's grid as changed markedly since the energy shortage event in 2020, and changed for the better. The latest tracking data from the Commission Energy Division shows that between January 1, 2020, and February 28, 2026, 28,784 MW of nameplate capacity[21] was added to CAISO's system, almost all of it new clean generation and storage resources.

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[19] ESPs are required to meet statewide green power policy goals, but customers may choose to exceed these goals and accelerate green power development.

[20] D.21-06-033 at p. 19.

[21] Energy Division, Resource Tracking Data as of February 28, 2026, p. 4, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-february-2026-release.pdf.

In fact, storage is the predominant new resource, with over 14 GW of new capacity installed.[22] These storage additions have shifted the RA market from one of scarcity in 2020 to one of surplus. As load-serving entities in California, ESPs are subject to the same Resource Adequacy obligations as all other LSEs and are meeting those requirements. Recent analysis of the 2025 RA market by Energy Division Staff has found that "by the [month-ahead (MA)] filing deadline for all months in 2025, all individual LSE deficiencies observed in the [year-ahead (YA)] filings had fully cured their YA deficiencies and procured enough to meet their MA requirements."[23] The report showed that even in the month of September, when the RA market is tightest, the system had more than enough RA qualified capacity to meet RA requirements and stated "filing outcomes from the first year of binding [slice-of-day (SOD)] implementation indicate that LSEs were able to transact within the current RA market to fully meet hourly SOD compliance."[24]

ESP compliance with RA requirements is also demonstrated by data on RA citations issued to LSEs with RA deficiencies. The figures below show that the number of RA violations for ESPs has dropped to zero in 2025. [25]

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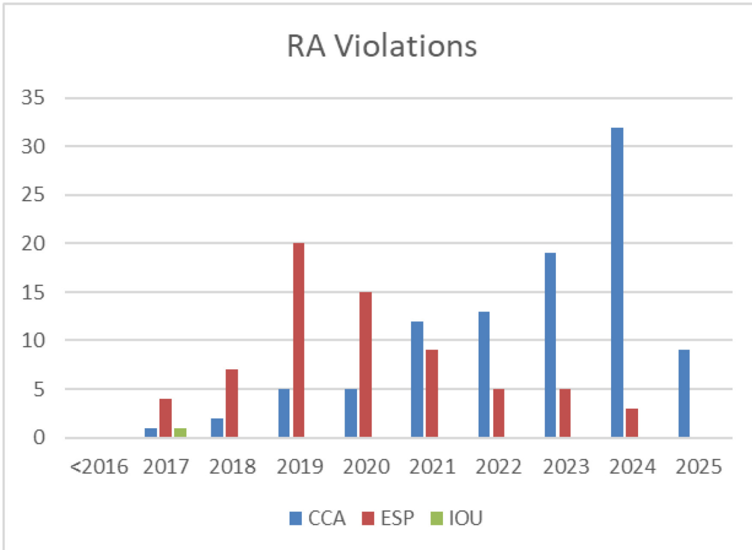
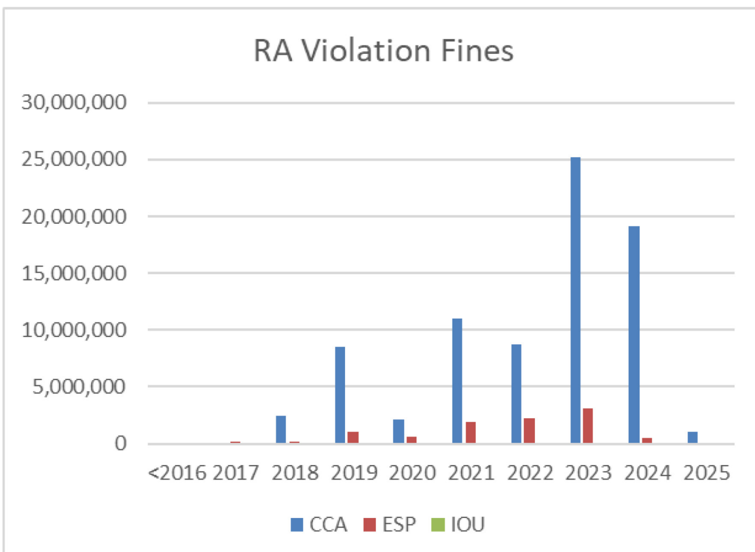
[22] *Ibid*, p. 5.

[23] Energy Division, *Report on Transactability within the Slice of Day Resource Adequacy Framework*, February 2026, p. 15, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M599/K960/599960179.PDF.

[24] *Ibid*. p. 17.

[25] Source: EUB Citations, August 2025.





ESPs are obligated to contribute to these increases in procurement of new resources and RA through their respective IRP and RA requirements the same as their Community Choice Aggregator (CCA) and IOU counterparts. As discussed above, the 2025 Energy Division Staff analysis of the RA market shows that all LSEs met their 2025 RA requirements, including ESPs.

ESPs who did not opt out of IRP procurement also collectively met IRP procurement requirements under D.19-11-016.[26]

Unfortunately, Energy Division Staff has not, to date issued updated progress reports showing compliance with the more recent IRP and Mid-Term Reliability (MTR) procurement orders. The most recent available report only covers through December 1, 2024.[27] That is significant because under D.21-06-035,[28] LSEs were not subject to IRP procurement penalties until June 1, 2025, providing some leeway for LSEs to "catch-up" to their requirements as of that date. The existing report therefore does not reflect compliance performance after that critical date, nor does it capture the substantial addition of 4,536 MW of storage in 2025 reflected in the more recent resource tracking report.[29] Once added, ESP compliance with IRP requirements will be far more accurate and markedly improve.

The experience of ESPs in California also differs significantly from Texas power marketers. ESPs in California, as discussed above, must meet RA market and IRP procurement requirements and are doing so. In 2021, Texas had no such requirements, making the reliability situation there an unsuitable comparison.

From a reliability perspective, now is a good time to reconsider the DA Decision. The RA market reform toward the SOD standard required a large effort from Energy Division Staff but is

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[26] Energy Division, *Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement*, August 2023 Data Filings, p. 14, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/publicirpcompliancereport080123.pdf.

[27] Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf.

[28] D.21-06-035, Conclusion of Law 26.

[29] Energy Division, Resource Tracking Data as of February 28, 2026, p. 6, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-february-2026-release.pdf.

now successfully implemented. As indicated above, the RA market is now in surplus. The largest reliability challenge on the horizon is meeting new load growth.

As discussed in Section IIB of this Petition, ESPs are better suited at preventing cost shifting to existing customers than CCAs and IOUs to meet the needs of new large customers because ESPs will place such customers under dedicated contract. These contracts will provide certainty to the ESPs, who can then properly finance deals to serve this load without risk to other customers and with no additional effort required from the Commission. Contrary to claims by the DA Decision that reopening DA would "destabilize" the market,[30] allowing ESPs to serve new customers will add contractual certainty, enhance system reliability and insulate residential and small customers from the rate increases that could occur should the new load be served exclusively by other LSEs.

E. The Alleged Increase in GHG Emissions has Also Been Addressed

In 2020, the GHG emission rate data relied upon in D.21-06-033 came from the California Energy Commission's Power Content Labels (PCLs). The labels reported that ESPs relied heavily upon "system power" for generation beyond that needed for RPS compliance. This system power is assigned a GHG-emissions factor similar to that of natural-gas powered generation. Even though the ESPs complied with the RPS requirements, ESPs were criticized for relying upon system power and not procuring RPS power in excess of the requirements.

The PCL calculations do not align with the methodology underpinning the GHG benchmarks assigned to individual LSEs in the IRP proceeding. For instance, the PCLs reflect the ability of LSEs to "net" solar generation in excess of their load (including battery charging) during sunny hours against fossil generation or system power in other hours, effectively "offsetting" those

[30] D.21-06-033 at p. 19.

emissions. An example of this is PG&E in 2024, whereby the utility's PCL shows that it is 100% carbon free. However, at the same time, it owns and operates 1,330 MW of gas combined cycle plants and 160 MW of gas peakers. In 2024, these plants generated 6 million MWhs, which, if assigned to PG&E, would equal 25% of its retail bundled load.

Implementation of hourly product reporting in 2028 is expected to bring the PCL emissions calculations into closer alignment with the IRP methodology. However, the PCL will still provide an imperfect measure of LSE progress towards meeting the IRP benchmarks on account of its focus on hourly energy matching. Energy matching does not optimize portfolios with consideration of system value of resources and systemwide reliability, which are explicitly modeled in the IRP.

The bottom line is that as more aggressive GHG goals are imposed on all LSEs, the difference in average GHG emissions between ESPs and other LSE has narrowed, and in many cases, already been erased. It will continue to trend downward as the State meets its carbon reduction goals.

F. The Concerns Regarding RPS Procurement and Criteria Air Pollutants are Unfounded.

The DA Decision expressed concern that ESPs procured lower amounts of RPS-qualified energy than other LSEs and that lifting the DA cap would result in lower amounts of RPS energy procurement and therefore higher criteria air pollutants.[31] However, all LSEs are subject to the same RPS and criteria air pollutant standards. To meet RPS requirements, ESPs must procure

[31] DA Decision, at p. 11.

adequate amounts of RPS-qualified energy, including energy supplied under long-term contract. Recently, ESPs met requirements for the 2021-2024 RPS compliance period.[32]

As with GHG reduction requirements, the IRP process also requires LSEs to measure reductions in criteria air pollutants to show reductions in these pollutants per statutory goals in Public Utilities Code Section 454.52. Although the Commission has not adopted air pollution reduction targets as it has with GHG emissions, if it does, ESPs will be subject to those requirements like all other LSEs.

ESPs may also exceed these requirements at the DA customer's option. This is comparable to CCA and IOU voluntary offerings of cleaner power products. Therefore, an ESP having lower amounts of RPS power than another LSE should not automatically be assumed to be a failure of the ESP. It likely just reflects that the ESP customer base has lower desire to exceed RPS requirements on a voluntary basis due to cost concerns. There is nothing improper or illegal when ESPs provide customers the option to exceed RPS requirements or not. AReM members have executed customer agreements with such above-the-RPS options.

G. Enrollment in DA is Currently a Very Involved Process, Yet Customers are Eager to Sign Up

Signing up for DA service is an unnecessarily protracted and involved process. The DA Lottery Process is a randomized system used to allocate any "load space" that becomes available when existing DA customers leave the program or return to utility service. It involves the following five-step process:

[32] *See,* CPUC, *2025 California Renewables Portfolio Standard Annual Report*, November 2025, page 23.

1. **Annual Submission Window:** Each year, typically during the second full business week of June, businesses must submit a “Six-Month Notice to Transfer” to their utility (PG&E, SCE, or SDG&E). The Upcoming Window is June 8, 2026 – June 12, 2026.
2. **Randomization:** After the window closes, utilities assign a random number to each valid submission.
3. **Waitlist Placement:** If no space is immediately available under the cap, customers are placed on a waitlist in the order determined by their lottery number.
4. **Annual Reset:** The waitlist expires at the end of each calendar year. To participate the following year, businesses must re-apply during the June window; previous priority does not carry over.
5. **Acceptance Window:** Selected customers typically have 15 business days to accept the offer and then 45 days to complete a Direct Access Service Request (DASR).

Despite this overly complex requirement, both DACC and AReM members have attested that there is an unmet desire by customers to utilize DA, as indicated in the attached declaration. CLEU’s members have attempted to increase the amount of load under DA unsuccessfully.

It is notable to compare this complex process with what is necessary to become a new IOU customer or new CCA customer. For example, to become a new Southern California Edison (SCE) customer, their website simply says:

> **Turn Service On & Off For Your Home**
> Moving to a new home? You’re at the right place, make a selection below & get started!
>
> **What You'll Need To Get Started**
> - Driver’s License / ID
> - Social Security Number[33]

[33] https://www.sce.com/customer-service-center/start-stop-move-service

To become a new customer of the Clean Power Alliance (CPA), its website says:

> If your community recently joined CPA service, you will receive a minimum of four (4) notices by mail advising you of your enrollment in Clean Power Alliance; two (2) before and two (2) after the switch from Southern California Edison to Clean Power Alliance. These notices will be mailed by Clean Power Alliance, not by Southern California Edison. To check your status, call us at 888-585-3788 or email us at customerservice@cleanpoweralliance.org.
>
> New customers who move into the existing Clean Power Alliance service area are automatically enrolled into Clean Power Alliance and will be mailed two notices within the first sixty days of service with information about their options.[34]

To summarize, to become an SCE customer you need only to provide a driver's license and social security number. You become a CPA customer simply by residing within its jurisdiction unless you affirmatively take steps to reject CPA service. The same is true for all CCAs. The best indicator of DA program success is subscription levels. On that basis DA is clearly beneficial to customers, based on their actions. DA has for years been oversubscribed on two IOUs and nearly so on the third. This in spite of the facts that (a) taking bundled IOU service or CCA service is the path of least resistance for customers, and (b) taking DA service involves a complex lottery process and a clunky acceptance process. The obstacles on the path to DA placed by the Legislature, the IOUs, and the CPUC are daunting. Because they cannot have more load served by DA, CLEU's members have also made decisions to locate new energy intensive campuses or projects outside of California when possible, because California's electricity rates are simply uncompetitive with our neighboring states. Thus, the lack of DA expansion is harming California's economy. Despite this dramatic disparity in the ease of service under DA, **customers continue to pursue DA to the extent legally possible!** The Commission needs to modify the DA Decision to permit them that ability.

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[34] https://cleanpoweralliance.org/faqs/#:~:text=Clean%20Power%20Alliance%20already%20serves,service%20from%20Clean%20Power%20Alliance?

III. CONCLUSION.

Approval of this request would be reasonable and appropriate for several reasons. First, the factors that caused the Energy Crisis and caused DA to be capped starting over 25 years ago have long since been addressed by both the Legislature and this Commission.

Second, the DA Program is well-suited to meet the needs of new large commercial loads, such as data centers. Data center customers could obtain service from an ESP under a dedicated contract, while other customers bear no risk of generation rate increases or stranded costs.

Third, ESPs are obligated to contribute to the increases in procurement of new resources and RA through their respective IRP and RA requirements the same as their CCA and IOU counterparts. As discussed above, the 2025 Energy Division Staff analysis of the RA market shows that all LSEs met their 2025 RA requirements, including ESPs. ESPs who did not opt out of IRP procurement also collectively met IRP procurement requirements under D.19-11-016

Fourth, ESPs and all other LSEs are required to submit to the Commission long-term IRP plans which include portfolios that require compliance with GHG emissions benchmarks. ESPs are required to procure adequate amounts of RPS-qualified energy, including energy supplied under long-term contract. In the most recent 2021-2024 RPS compliance period, ESPs demonstrated compliance.

Finally, the Commission has not yet adopted air pollution reduction targets as it has already done with GHG emissions. However, when it does, ESPs will be subject to the same requirements as are applicable to all other LSEs.

Given the foregoing, it would be entirely appropriate for the Commission to modify the Decision and send a positive recommendation to the Legislature that it should remove the cap on DA. Revisions to the Decision to accomplish the results sought herein are attached as Exhibit A to the pleading.

The Competition Parties thank the Commission for its attention to this request.

Respectfully submitted,

Daniel W. Douglass
DOUGLASS, LIDDELL & KLATT

Attorneys for the
DIRECT ACCESS CUSTOMER COALITION
ALLIANCE FOR RETAIL ENERGY MARKETS

And on behalf of the Competition Parties

April 6, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access.	R.19-03-009

DECLARATION OF DANIEL W. DOUGLASS
IN SUPPORT OF PETITION FOR MODIFICATION

I, Daniel W. Douglass, declare as follows:

1. I am counsel of record for the Alliance for Retail Energy Markets and the Direct Access Customer Coalition. I have held this position since 1998 and 2008, respectively. I make this declaration based on my own personal knowledge, and if called upon to testify, I could and would testify competently to the facts stated herein.
2. The purpose of this declaration is to support the factual allegations regarding new facts and changed circumstances set forth in the Petition for Modification filed by the Competition Parties in this proceeding.
3. Since the issuance of D.21-06-033 (Decision), the Commission has engaged in extensive efforts in its Integrated Resource Planning (IRP) proceedings in Rulemakings (R.) R.20-05-003 and R.25-06-019. These efforts occurred more than one year after the Decision was issued.
4. Further, AB 1373 (Chapter 367 of 2023) modified the IRP statutes, specifically Section 454.51, to clarify the Commission's ability to order ESPs to pursue procurement of long-term contracts. The bill addressed many of the CPUC's concerns with its ability to order ESPs to pursue long term procurement as it equalized the treatment of all LSE types concerning the procurement of both resource adequacy and integrated resource planning. This legislation and the Commission's subsequent implementation efforts occurred more than one year after the Decision was issued.
5. Most recently, in R.25-06-019, the Commission issued the IRP Decision. Concurrently herewith, certain members of the Competition Parties are filing an application for rehearing of the 2026 IRP Decision (Rehearing Application). This effort occurred more than one year after the Decision was issued.
6. The Rehearing Application alleges that the IRP Decision will cause inappropriate cost shifting to DA customers, counter to the requirements of Public Utilities Code Sections 397, 365.2, 366.2(d)(1), 366.3 and 454.52. The cost shift occurs because the IRP Decision (despite expressly identifying anticipated new load growth, including data center and electric vehicle charging load as principle drivers of the need for incremental procurement, it goes on to simultaneously allocate procurement responsibility of this procurement to all LSEs—including all ESPs who will be ineligible to serve this incremental load due to the cap on California's Direct Access (DA) program, ESPs will be unable to serve this new load.
7. ESPs cannot enroll new customers in most of the state and cannot meaningfully serve new large loads, including data centers and electric vehicle charging stations.

8. Per the facts cited above, I declare that this Petition could not have been filed within one year of the issuance of the Decision.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on April 6, 2026, at Agoura Hills, CA.

Daniel W. Douglass

Daniel W. Douglass

Exhibit A

Suggested Revisions to D.21-06-033

Title Page and Page 2 Delete AGAINST in title of the Decision so it reads DECISION RECOMMENDING FURTHER DIRECT ACCESS EXPANSION

Page 2 This decision contains the Commission's recommendation to the Legislature ~~against~~ for further expansion of the Direct Access program at this time.

…

~~After review of the Commission Staff Report1 attached to this decision, t~~ The California energy crisis that occurred between 2000 and 2001, was characterized by market manipulation, supply shortages, and rolling blackouts. It directly led to the suspension of Direct Access, via Assembly Bill 1X in 2001. The bill was designed to prevent further customer migration from the investor-owned utilities (IOUs) so that the IOUs could stabilize their load and procurement obligations. Limited direct access for non-residential users was slowly reopened years later under Senate Bill 695 (2009) and expanded by Senate Bill 237 (2018).

In other words, events of over a quarter of a century ago were the cause of DA suspension and the cap. Those causative factor to those events have long since been addressed by both the Legislature and the Commission in multiple ways. The Legislature's enactment of the RA, RPS, and IRP statutes provided direction to the Commission with respect to oversight of ESP short- and long-term procurement activities.

Therefore, the Commission concludes that at this time, expansion of Direct Access to all non-residential customers would not present an unacceptable risk to the state's long-term reliability goals. Further, based on the current procurement practices of Direct Access providers, we are ~~unable~~ able to ensure that expansion of Direct Access would not result in increased greenhouse gas emissions, criteria air pollutants, and toxic contaminants when compared to maintaining the current cap on Direct Access. Therefore, we ~~cannot~~ recommend expanding Direct Access at this time.

~~The Commission considers electric system reliability against the backdrop of two recent grid reliability events.~~

Page 3 Delete first two paragraphs dealing with the 2020 heat waves and the 2021 Texas experience.

Page 4 Currently, IRP forecasts that retirement of once-through-cooling plants as well as increased electric load from data centers, building electrification and transportation electrification will lead to capacity deficits. These capacity deficits could be significant and will require new generation resources to be built. This means that in the coming years load serving entities will need to invest in these new generation resources through long-term contracts to ensure grid reliability. ~~Reopening Direct Access would significantly complicate the state's near-term and long-term efforts to ensure grid~~

~~reliability for all ratepayers if individual load serving entities lose load due to load migration and are unable to enter into long-term commitments for new generation.~~ The Commission has acted to address these capacity deficits by its recent approval of decision (D.) 26-02-057, the *Decision Requiring 2029-2032 Electric Resource Procurement And Transmitting Portfolios For 2026-2027 Transmission Planning Process*. This decision requires direct access providers (ESPs) to procure a share of 6 gigawatts of new capacity. Based on the recent reported performance of ESPs, the Commission is confident that these obligations will be fulfilled.

The Commission views grid reliability as one of its top priorities. The Staff Report issued for comment in September 2020 recommended expanding Direct Access at a rate of ten percent each year. However, after considering the reliability events and the IRP forecasts for additional generation, the Commission is recommending ~~against~~ Direct Access expansion at this time. Expanded Direct Access ~~would result in further fragmentation of the market and raises~~ should not raise serious electric system reliability concerns. ~~These reliability concerns, coupled with Direct Access providers' primary reliance on unspecified power sources, form the basis for the Commission's recommendation against~~ The DA Program is well-suited to meet the needs of new large commercial loads, such as data centers. Under this program, a data center customer could obtain service from an ESP under a dedicated contract that is negotiated between the customer and the ESP. Such arrangements would be a win-win situation for large load customers and the rest of the state. New large loads get the advantage of flexibility in contracting that can meet their needs, including providing the customer's desired level of green power attributes, while other customers bear no risk of generation rate increases or stranded costs. Therefore the Commission now recommends the expansion of Direct Access.

Pages 7-19 Delete Section 1.2 and Section 2 in their entirety.

Page 19 In consideration of the ~~concerns raised in the Staff Report and the~~ urgent reliability challenges that the state faces, and the Action undertaken by D.26-02-057, the Commission ~~cannot~~ finds that expansion of Direct Access will ~~ensure~~ not impair electric system reliability. Therefore, the Commission recommends lifting the cap on Direct Access at this time. ~~The existing uncertainties around procurement planning raised by the August 2020 energy shortage and the February 2021 power crisis in Texas have required California agencies to take a deeper look at reliability issues.~~

~~Although the immediate cause of the Texas reliability events was extreme weather that the Texas grid had not prepared for, and Texas electricity markets are governed by a different regulatory regime, the massive outage showed what can happen if regulatory oversight is too limited. Even when wholesale power prices reached their cap of $9,000 per MW hour, customer load reduction was not~~

Pages 20-21 ~~sufficient to avert outages. Some customers who did have power experienced extreme rate and bill impacts. An extreme example of the bill impacts was felt by customers of Griddy, a Texas direct retail provider that charges customers the wholesale price as a passthrough, encouraged customers to switch providers during the outage to avoid paying the $9,000 wholesale rate. Ironically, in the comments filed in this proceeding in 2020, Direct Access Parties, such as NRG, pointed to the Texas energy market as a~~

~~model of a fully competitive market; clearly, the Texas model now serves as a warning to proceed with caution, careful planning, and continuing evaluation of the effectiveness of planning structures given changing market and weather conditions. To ensure electric system reliability, the Commission recommends not opening Direct Access to additional load at this time.~~

B. The recommendations ~~are~~ is consistent with the state's greenhouse gas (GHG) emission reduction goals.

~~ESPs' current procurement practices may indicate that load migration from IOUs or CCAs to ESPs could lead to a net decline in RPS procurement relative to the current forecast, which could lead to a net reduction in GHG emission reductions compared to not reopening Direct Access.29 The Staff Report relies on the ESPs' 2019 PCL to determine that approximately 70 percent of the ESPs' energy resource are from unspecified power. California Air Resources Board has determined that unspecified power has a GHG emissions content that is slightly higher than natural gas generation.~~

~~The Direct Access Parties state that they intend to comply with the new RPS obligation to secure at least 65 percent of their RPS resources through long-term contracts by 2024. This is the deadline pursuant to statute. However, the IOUs and CCAs have consistently procured RPS resources in excess of state requirements. Thus, allowing additional load to migrate to Direct Access would likely result in increased GHG emissions compared to the status quo.~~

~~We conclude that we cannot find that reopening Direct Access would be consistent with the state's GHG emission reduction goals and therefore cannot recommend reopening at this time.~~

In 2020, the GHG emission rate data relied upon in D.21-06-033 came from the California Energy Commission's Power Content Labels (PCLs). The labels reported that ESPs relied heavily upon "system power" for generation beyond that needed for RPS compliance. This system power is assigned a GHG-emissions factor similar to that of natural-gas powered generation. Even though the ESPs complied with the RPS requirements, ESPs were criticized for relying upon system power and not procuring RPS power in excess of the requirements.

The PCL calculations do not align with the methodology underpinning the GHG benchmarks assigned to individual LSEs in the IRP proceeding. For instance, the PCLs reflect the ability of LSEs to "net" solar generation in excess of their load (including battery charging) during sunny hours against fossil generation or system power in other hours, effectively "offsetting" those emissions. An example of this is PG&E in 2024, whereby the utility's PCL shows that it is 100% carbon free. However, at the same time, it owns and operates 1,330 MW of gas combined cycle plants and 160 MW of gas peakers. In 2024, these plants generated 6 million MWhs, which, if assigned to PG&E, would equal 25% of its retail bundled load.

Implementation of hourly product reporting in 2028 is expected to bring the PCL emissions calculations into closer alignment with the IRP methodology. However, the PCL will still provide an imperfect measure of LSE progress towards meeting the IRP benchmarks on account of its focus on hourly energy matching. Energy matching does not optimize portfolios with consideration of system value of resources and systemwide reliability, which are explicitly modeled in the IRP.

The bottom line is that as more aggressive GHG goals are imposed on all LSEs, the difference in average GHG emissions between ESPs and other LSE has narrowed, and in many cases, already been erased. It will continue to trend downward as the State meets its carbon reduction goals.

Page 21-22 ~~However, we cannot ensure that reopening Direct Access would not increase criteria air pollutants and toxic air contaminants. The Commission notes that ESPs rely primarily on unspecified power from the CAISO energy market and that most criteria pollutants and toxic air contaminants are the result of unspecified power transactions. Increased reliance on unspecified power could result in an increase in criteria pollutants and toxic air contaminants.~~

ESPs are also subject to the same requirements for RPS and criteria air pollutants as other LSEs, and ESPs are successfully meeting RPS requirements. To meet RPS requirements, ESPs must procure adequate amounts of RPS-qualified energy, including energy supplied under long-term contract. Recently, ESPs met requirements for the 2021-2024 RPS compliance period.

D. The recommendation~~s~~ does not cause undue shifting of costs to bundled-service customers of an electrical corporation or to direct transaction customers.

As discussed above, the Commission has determined that it can~~not~~ make all of the Required Findings necessary to recommend Direct Access expansion. The potential for undue cost-shifting, and the mechanisms for preventing cost-shifting to bundled-service customers, is addressed through various Commission processes such as the annual Energy Resource Recovery Account (ERRA) proceedings for each of the large IOUs. These processes are complex and provide assurances that cost-shifting is addressed thoroughly. ~~evolving. Because the Commission has already determined that it cannot recommend expansion of Direct Access, it is not necessary for this decision to make a specific finding regarding cost-shift in an expanded Direct Access. Also, we note that, according to the Staff Report, Direct Access expansion could result in cost increases for all customers if the expansion results in capacity constraints and reliability events caused by underinvestment in new resources.~~

Page 22 **4. Conclusion**

The Commission interprets section 365.1 to require that all four Required Findings can be made. ~~As discussed above, the energy market in California is in flux and highly fragmented. The record demonstrates a wide range of complexities and potential risks that could result from reopening, especially in terms of electric reliability. Due to this high level of uncertainty,~~ Through this decision, the

Commission ~~cannot meet~~ hereby makes the four Required Findings and therefore ~~cannot~~ recommends that the Legislature act to lift the cap on Direct Access. ~~a schedule to expand Direct Access that meets these requirements.~~

~~To fulfill~~ Doing so would complement the Commission's primary responsibility in ensuring grid reliability, implementing the state's ambitious GHG and air quality goals, and encouraging the construction of long-term renewable generation resources~~, the Commission recommends that the Legislature not expand Direct Access at this time~~.

Pages 22-26 Delete Sections 5 and 6.

Pages 27-29 Delete Findings of Fact and Conclusions of Law and replace with:

Findings of Fact

1. In the years since the issuance of D.21-06-033, both the Legislature and this Commission has taken several steps to enhance and ensure reliability.
2. The Legislature's enactment of the RA, RPS, and IRP statutes provided direction to the Commission with respect to oversight of ESP short- and long-term procurement activities.
3. Through its issuance of D.26-02-057, the Commission has ordered load-serving entities to undertake additional reliability procurement between 2029 and 2032, to pursue any viable projects that can still qualify for Federal tax credits or other incentives, as well as to continue the momentum of annual procurement activity that began under the Mid-Term Reliability (MTR) and supplemental MTR requirements in Decision (D.) 21-06-035 and D.23-02-040, respectively.
4. The new procurement required is 2,000 megawatts (MW) of net qualifying capacity (NQC) by 2030, another 2,000 MW NQC, by 2031, and an additional 2,000 MW NQC by 2032.
5. The current cap on direct access is a remnant from the 2000-2001 energy crisis. Since that time, conditions in the state have improved measurably.
6. Since the time of the DA Decision in 2021, the outlook for load growth in California has fundamentally changed from one of incremental growth to rapid load growth. The largest drivers of load growth according to the California Energy Commission's California Energy Demand Integrated Energy Policy Report (IEPR Forecast) are the anticipated needs to serve electric vehicle charging, new large data centers and "additional fuel switching."
7. Storage is the predominant new resource, with over 14 GW of new capacity installed.
8. Allowing ESPs to serve new customers adds contractual certainty, enhance system reliability and insulate residential and small customers from the rate increases that could occur should the new load be served exclusively by other LSEs.
9. As more aggressive GHG goals are imposed on all LSEs, the difference in average GHG emissions between ESPs and other LSE is narrowing, and in many cases

already erased, and will continue to trend downward as the State meets its carbon reduction goals.

10. All LSEs are subject to the same RPS and criteria air pollutant standards.
11. To meet RPS requirements, ESPs must procure adequate amounts of RPS-qualified energy, including energy supplied under long-term contract. Recently, ESPs met requirements for the 2021-2024 RPS compliance period.
12. There is an unmet desire by customers to utilize direct access as evidenced by the demand demonstrated in the utility sign-up processes.

Conclusions of Law

1. Expanding Direct Access will not create unacceptable risks to electric system reliability.
2. The recommendation herein will not cause undue shifting of costs to bundled-service customers of an electrical corporation or to direct transaction customers.
3. Expanding Direct Access is consistent with the state's GHG emission reduction goals and should not increase either criteria air pollutants or toxic air contaminants.