APPENDIX A

Final Report Providing an Assessment of Expansion of Direct Access

Pursuant to Senate Bill 237

California Public Utilities Commission Staff Report

Pursuant to Senate Bill 237 (2018) and R. 19-03-009

September 14, 2020 (Revised May 7, 2021)

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Key Acronyms

AB	Assembly Bill
CCA	Community Choice Aggregation
CEC	California Energy Commission
ESP	Electric Service Provider
GHG	Greenhouse Gas Emissions
IRP	Integrated Resources Planning
IOU	Investor-Owned Utility
LSE	Load Serving Entity (includes CCAs, ESPs, and IOUs)
LLTP	Long Term Procurement Planning
NEM	Net Energy Metering
PCIA	Power Charge Indifference Adjustment
POLR	Provider of Last Resort
SB	Senate Bill
RA	Resource Adequacy
REC	Renewable Energy Credits
RPS	Renewables Portfolio Standards

1. Introduction

1.1. Overview

In 2018 the Legislature approved Senate Bill (SB) 237 (Hertzberg) that required the California Public Utilities Commission (CPUC) to 1) increase the cap on the amount of demand that can be serviced by competitive Electricity Services Providers (ESPs) through Direct Access, also referred to as direct transactions and 2) provide recommendations to the Legislature on implementing further expansion of Direct Access, including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.

Consistent with the requirements of SB 237, this Staff Report provides an assessment of the provisions identified in Public Utilities (P.U.) Code Section 365.1 (f) for the Legislature's consideration in their determination of further reopening.

Staff's assessment of the impacts of reopening Direct Access pursuant to P.U. Code 365.1(f) is summarized as follows:

- Large-scale generation resources are needed because the state has a major capacity shortfall over the next decade. The CPUC has ordered 3300 MW of new generation to be built by 2023 and estimated that an additional 7500 MW is needed by 2026.
- The load migration that would be enabled by reopening Direct Access leaves all LSEs uncertain about future load, making it challenging for any LSE, including the CCAs and IOUs, to build the large-scale generation resources the state needs to ensure reliability in the future.
- 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.
- If past procurement indicates future outcomes, then load migration from IOUs or CCAs to ESPs may lead a net decline in RPS procurement, relative to maintaining the current cap on Direct Access, which may increase GHG emissions and increase criteria air pollutants and toxic air contaminants.
- Shortfall in generation capacity drives up the cost of energy for all customers adversely impacting all ratepayers.

1.2. Objectives and Scope

Pursuant to SB 237 the CPUC is required to provide the Legislature with recommendations on the further reopening of Direct Access. Energy Division staff prepared this Staff Report in order to support the CPUC in meeting requirements of SB 237.

Public Utilities (P.U.) Code 365.1 (f) states that:

> (f)(1) On or before June 1, 2020,[1] the commission shall provide recommendations to the Legislature on implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.
>
> (2) In developing the recommendations pursuant to paragraph (1), the commission shall find all of the following:
>
> (A) The recommendations are consistent with the state's greenhouse gas emission reduction goals.
>
> (B) The recommendations do not increase criteria air pollutants and toxic air contaminants.
>
> (C) The recommendations ensure electric system reliability.
>
> (D) The recommendations do not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.

This Staff Report provides an assessment of the provisions identified in P.U. Code Section 365.1(f) for the Legislature's consideration in their determination of further reopening in Direct Access.

Direct Access, originally adopted in 1996 as part of California's energy restructuring initiative and authorized by P.U. Code Section 365.1, is a retail electric service option whereby customers may purchase electricity from a competitive non-utility entity called an ESP. The amount of electric load that can be serviced by Direct Access has been capped by statute since 2002. SB 237 required the CPUC to increase the allowable Direct Access load by 4,000 gigawatt-hour (GWh).

In 2002, Assembly Bill (AB) 117 added P.U. Code Section 331.1, which created CCAs as an alternative provider or retail electricity services. In 2014, CCAs served only around 0.5 percent of all load in IOU territory; in 2021 it is estimated that CCAs will account for approximately 33 percent of load in IOU territory.

While CCA growth is an important market context for assessing the possible effects of expanding the market for Direct Access, pursuant to SB 237, this report focuses specifically on an assessment of the likely effects and risks of expanding Direct Access and is not intended to assess the impacts of CCA growth.

Direct Access currently serves approximately 16 percent of load in IOU territory with the implementation of SB 237. Figure 1 shows the proportion of load that is served by Direct Access in IOU service territory. The additional 4,000 GWh allowed is equivalent to 2.35 percent of the total

[1] Issuance of this report was delayed due to the Covid-19 and economic emergency.

load. Figure 1 shows the estimated 2021 load shares served by Direct Access, CCAs, and IOUs and the load that will become eligible to switch to Direct Access in 2021 with the 4,000 GWh increase allowed by SB 237.

Figure 1: 2021 Direct Access Load (GWh) and Eligible Direct Access Load (GWh)

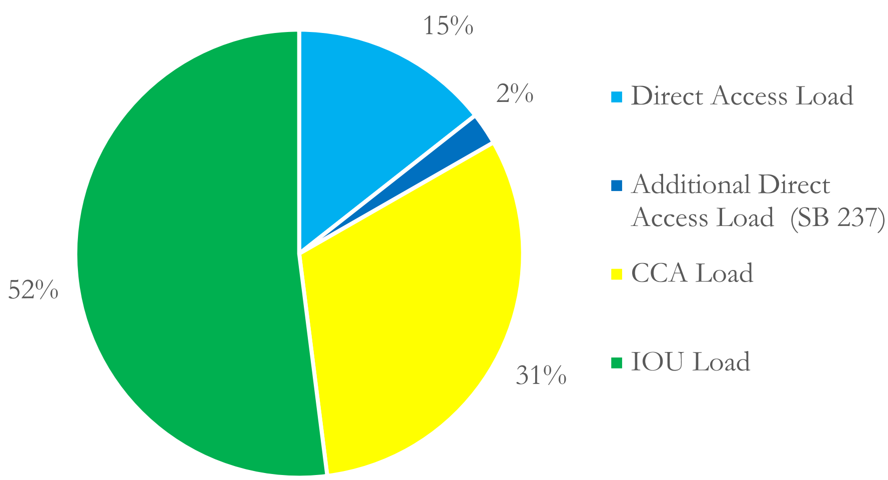
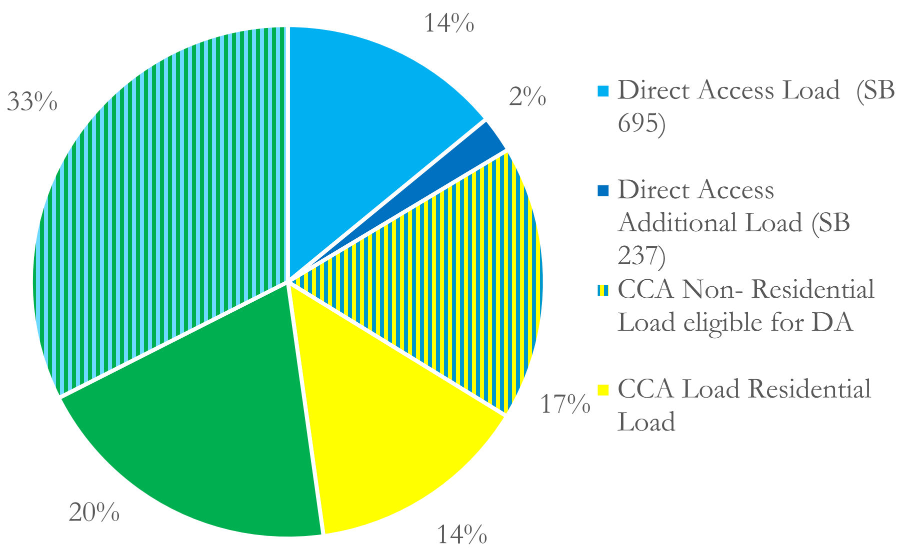


Figure 2, below, shows the current Direct Access load and additional load that will become eligible for Direct Access in 2021 pursuant to SB 237. As Figure 2 below indicates, 47 percent of the current IOU and CCA load could move to Direct Access if the Legislature decides to re-open the entire non-residential market to Direct Access, as contemplated in SB 237, while 38 percent of IOU and CCA load that serves residential customers would not be eligible for Direct Access under SB 237.

Figure 2: Direct Access Load (GWh) and Direct Access Eligible Load (GWh) if Direct Access Becomes Eligible to All Non-Residential Load



1.3. Background on Direct Access and Retail Choice

Direct Access was originally adopted in 1996 as part of California's electricity restructuring initiative, AB 1890 (Brulte, 1996). Prior to AB 1890, vertically integrated IOUs owned and operated generation, transmission, and distribution systems, and provided retail services to all customers under regulation from the CPUC. Direct Access provides retail choice to customers by allowing them to purchase electricity directly from an ESP while the IOUs continue to supply the transmission and distribution services needed to transport power to the customer. AB 1890 opened Direct Access to both residential and non-residential customers.

In 2000-2001, active market manipulation in a tight energy market led to large spikes in electricity costs and rolling blackouts across the state. The IOUs were unable to recover the costs of procuring electricity in the wholesale energy market due to fixed retail rates and mounting costs to procure generation. Ultimately, this led to PG&E's first bankruptcy in 2001. During this period, many Direct Access providers left the market, returning their customers to IOU service.

In response to the crisis, the Legislature approved AB1X (Keely, 2001) to resolve the shortage of energy available in the day ahead energy markets and stabilize energy prices. Among other actions, AB1X suspended additional Direct Access enrollment.

From 2001 to 2010, existing Direct Access customers were allowed to continue on Direct Access and were permitted to shift between ESPs, but no additional customers were allowed to move to Direct Access. SB 695 (Kehoe, 2009) opened Direct Access to a limited amount of new non-residential load, which would be phased in over several years. SB 695[2] created a capacity "cap" of electric load that ESPs may serve but otherwise retained the main aspects of Direct Access suspension until further legislative action. The cap set by SB 695 was equal to the peak amount of load served by Direct Access prior to the electricity crisis. The new cap was roughly 13 percent of total load. In 2002, AB 117[3] established P.U. Code Section 331.1, which authorizes the implementation of CCA. AB 117 allows local government entities to form CCAs to purchase power for their communities from non-utility power suppliers. Per AB 117, customers are defaulted into CCA service when a CCA is formed in their service area, with an option to opt-out and return to utility service.

Following passage of SB 237 in 2018, the CPUC opened Rulemaking (R.)19-03-009. In the first phase of the rulemaking, the CPUC allocated the additional 4,000 GWh Direct Access load from SB 237 among the three IOU territories according to load share. To provide sufficient time for ESPs to comply with current year-ahead Resource Adequacy requirements, the additional Direct Access capacity went into effect on January 1st, 2021. In Phase 2 of R.19-03-009, the CPUC is addressing the requirement to provide recommendations to the Legislature on further reopening of non-residential Direct Access.

Since 2001, the legislature and CPUC have implemented a series of new regulations to ensure there is sufficient generation capacity available for system reliability. Among the key requirements adopted were the creation of long-term and short-term procurement requirements for LSEs through the Long-Term Procurement Planning (LTPP) and Resource Adequacy proceedings. AB 380 (Nunez, 2005) established Resource Adequacy requirements to meet near-term capacity needs. Resource Adequacy requirements were updated by SB 1136 (Hertzberg, 2018) to ensure sufficient capacity to meet system, local and renewable integration (flexible) needs. Following SB 350 (de Leon, 2015), the CPUC moved long-term planning into the Integrated Resource Planning (IRP) process, which considers both reliability and greenhouse gas emission reductions goals in a single proceeding and seeks to define an optimal path for realizing both goals.

As increased residential load have shifted from IOU to the CCAs, the legislature and the CPUC have instituted changes in RPS, RA, and IRP programs to ensure grid reliability, prevent cost shifting, and ensure provision of reliable power to customers at reasonable rates.

1.3.1 California Customer Choice Project

In 2017, the CPUC initiated California Customer Choice Project to examine the rapid evolution of California's electric sector and develop a report evaluating competitive retail electricity options. The results of the project were published in August 2018 as *California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market* (Customer Choice Paper). The Customer Choice Paper identifies shifts occurring in the electricity sector as a result of expanding customer choice and assesses markets outside of California for lessons learned. The paper also raises fundamental questions on how to simultaneously create more market choice for consumers, meet

[2] See P.U. Code Section 365.1(b)
[3] See P.U. Code Section 331.

statewide goals, and ensure California's energy policy core principles of affordability, reliability and decarbonization.

Following the Customer Choice Paper, CPUC staff published the *Choice Action Plan and Gap Analysis* (Action Plan) in December 2018 to identify critical policy issues associated with increased disaggregation of load and supply. CPUC staff also conducted an internal analysis to identify regulatory gaps that exist and actions that would help to ensure core principles are met if retail choice is pursued. This report is informed by, and expands upon, the analysis of these topics in the Action Plan.

1.3.2 Development of this Staff Report

On January 8, 2020, staff held a workshop to solicit input from stakeholders and parties to R.19-03-009. Parties provided informal comments in response to the discussion. Comments were provided by the Alliance for Retail Energy Markets (AReM), California Community Choice Association (CalCCA) California Large Energy Consumers Association (CLECA), Cogeneration Association of California (CAC), Commercial Energy of California (Commercial Energy), Direct Access Customer Coalition (DACC), Energy Producers and Users Coalition (EPUC), Pacific Gas and Electric (PG&E), Public Advocates Office (CalPA), Renewable Energy Buyers Alliance (REBA), Southern California Edison (SCE), and The Utility Reform Network (TURN). The Draft Report was informed by the comments and analysis of the participating parties, as well as past staff reports and decisions, which are cited below.

The Draft Report was issued by Ruling on September 28, 2020 inviting comments. Comments were submitted on October 16, 2020 and reply comments on October 26, 2020 by the aforementioned parties, as well as Vistra Energy Corp., Western Power Trading Forum, NRG Energy, Inc., Shell Energy of North America, The Regents of the University of California, and Advanced Energy Economy/Advanced Energy Buyers Group. The Final Report has been revised in consideration of comments raised by parties, and to update the analysis with the best available data. The proposed recommendations from staff were also eliminated from this report, to allow the Commission to reach its findings and make recommendations to the Legislature. While we are unable to discuss every comment raised on the report, we highlight some key issues raised and how they were addressed.

AREM raised questions about the interpretation of RA, which indicates that ESPs have a poor compliance record. While a greater number of the total number of RA citations issued between 2006 and 2019 have been issued to ESPs (85%), CCAs are responsible for 88% of the penalty amounts, some of which are still being litigated before the Commission. We agree that this was a misinterpretation and that RA citations are poor indication of the RA market, so this was removed from the report. Staff has updated the section with more recent analysis provided in the RA proceeding demonstrating the market capacity shortfall and updated the discussion of the implications.

Numerous parties expressed objection to the consideration of provisions to ensure no cost shifting for CCAs and requested its removal. That CCAs have full authority to establish exit fees or other charges, as approved by their governing boards, to ensure there is no shifting of costs to the CCAs' remaining customers as the result of customers moving to Direct Access or returning to bundled service. We note that we have deleted this section as out of scope of the report.

1.4. Potential Benefits of Expanding Direct Access

In their informal comments on the January 8th Energy Division workshop, parties discussed the potential benefits that expanding Direct Access can provide to commercial customers.

1.4.1 Expanded Direct Access will Increase Choices for C&I customers

ESP representatives point out that many commercial and industrial customers desire the retail options that Direct Access can offer. Since caps on total participation were instituted, the program has always been at capacity and there have been consistent waiting lists for the program. At the end of 2018, 6,951 GWh of customer load remained on the Direct Access waitlist.[4] While SB 237 increased the maximum allowable limit for Direct Access by 4,000 GWh, 2,000 GWh of which will come from the June 2020 Direct Access Lottery, it is reasonable to expect that demand for Direct Access service requests will increase if the cap is lifted.

1.4.2 ESPs Can Tailor Their Service to Customer Needs

Companies seek out Direct Access for various reasons. First, while the CPUC has no visibility into the rates ESPs charge their customers, it appears that Direct Access providers have generally been able to provide power at a significant cost-advantage to IOUs, and many Direct Access customers choose Direct Access in order to lower their overall energy bills. Lower rates are appealing to all customers but may be particularly important to large commercial and industrial customers for whom energy is a major component of overall costs. For this class of customer, particularly industrial customers with some degree of locational freedom, the search for less expensive electricity could lead them to consider moving production out of California. Direct Access may provide these customers an incentive to stay in the state.

Direct Access may also provide customers with competitive options and flexibility, allowing them to choose procurement products and rate designs. Customers may use Direct Access in order to pursue corporate GHG emission reduction initiatives. ESPs point out that they can provide customers with electricity services, such as load management, that are tailored to the customer's specific needs. Customers with multiple locations, such as large retailers, may seek Direct Access in order to aggregate load across different service territories and buy electricity services from a single provider. Buying from an ESP may facilitate customers who want to implement a unified energy management plan across jurisdictional boundaries and can facilitate the pursuit of corporate or institutional GHG goals by allowing companies to more efficiently plan and finance long-term, offsite investments in solar, wind, storage or other renewable assets.

[4] 2018 Direct Access Lottery Enrollment Report

1.5. Challenges of Implementing Direct Access

Large-scale load migration between LSEs will likely create structural challenges to California's system of electrical system planning. In recent years load migration has been driven primarily by the rapid growth of CCAs. Reopening Direct Access would allow nearly two-thirds of existing load, including load that has recently migrated to CCA service, to migrate between IOU, ESP and CCA service.

Competitive options and flexibility for non-residential customers also create challenges to building of large-scale generation resources. Direct Access customers make short term commitments to an ESP, generally signing 1 to 2-year contracts. ESPs have traditionally procured much of their energy in day-ahead and real-time markets and through short-term contracts. ESPs have recently begun to sign more long-term contracts in response to the 65 percent long-term contracting requirements for Renewable Procurement Standards (RPS). Because Direct Access customers make short-term commitments to an ESP, multi-year obligations are risky for ESPs. Expanding Direct Access increases the risks that insufficient long-term procurement contracts will be signed to build the resources needed to meet system reliability and GHG reduction targets, if ESPs fail to comply with their Resource Adequacy, RPS, and IRP obligations.

It is important to acknowledge that, to a certain degree, these planning and contracting challenges are caused by load migration in general, which includes load migration due to CCA expansion. In their informal comments to the January 8, 2020 workshop, several Direct Access representatives raised the concern that ESPs are held to a separate standard than CCAs. They questioned whether this report should go beyond challenges that are specific to Direct Access expansion and consider load migration in general. While the rapid growth of CCAs has, in fact, made planning and procurement to meet system reliability more challenging, the current legislative mandate under P.U. Code 366.2 does not cap the amount of load that can be served by CCAs. This report focuses on the statutory requirements of P.U. Code 365.1(f), as required by statute.

A rapid expansion of Direct Access will increase the challenges associated with load migration. Currently, the IOUs are experiencing a substantial amount of load departure annually with the launch and expansion of CCAs. There is also an insignificant amount of load returning to IOUs or migrating to ESPs, to the extent allowed by the current cap. This increased load migration will make long-term procurement more challenging for all LSEs, as will be further described in Section 2.

1.5.1 Mechanism to address market risks related to load migration may be developed but do not currently exist

The Customer Choice Project found that a central procurement entity that procures on behalf of all LSEs may resolve some of the procurement challenges caused load migration, since central procurement would be indifferent to which LSE is serving load.[5] The CPUC has recently adopted central procurement for local Resource Adequacy in two IOU territories—Pacific Gas & Electric

[5] California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August, 2018), p. 65.

(PG&E) and Southern California Edison (SCE)—to be implemented beginning in 2023.[6] However, this effort was largely opposed by the ESPs and the CCAs and, given the complexity introduced in response to parties concerns, its success is not yet clear.

Over time, market participants may also adapt to load migration and develop new ways to organize procurement to meet state planning requirements while also maintaining the flexibility they desire in competitive retail markets. For example, multiple CCAs or ESPs may collaborate to procure larger resources. However, currently these market-based approaches either do not exist or are in the very early stages of development. Expansion of Direct Access before these mechanisms have been developed and tested would present significant structural impediment to electric system reliability.

2. Assessment of Statutory Provisions of Reopening Direct Access

This section provides an assessment of the four statutory provisions identified in Public Utilities Code Section Code 365.1 (f)(2) that must be met in setting a recommended schedule for reopening of Direct Access. The statute directs the CPUC to find that the recommendations are consistent with the state's greenhouse gas (GHG) emission reduction, do not increase criteria and toxic air pollutants, ensure system reliability, and do not cause undue cost shifting to bundled customers. These provisions are considered below.

2.1. Impact of Direct Access Expansion on Greenhouse Gas Emission Reduction Goals

Under SB 32 (Pavley, 2016) the state must reduce GHG emissions to 40 percent below 1990 levels by 2030. SB 350 (de Leon, 2015) requires the California Air Resources Board to establish emission reduction targets for the electricity sector and for the CPUC to use those targets in developing Integrated Resource Plans for LSEs under its jurisdiction.

In order to meet 2030 GHG emission targets, California will need to build nearly 25,000 MW of new GHG-free resources, including over 12,000 MW of storage. This new capacity will need to achieve commercial operation by 2026 to replace retiring gas generation.[7] As major capital investments, new renewables projects cannot generally find financing without long-term power purchase agreements. Staff is concerned that expanding Direct Access at this time could undermine the market conditions needed to make the long-term commitments needed to finance and build the

[6] Decision (D.) 20-06-002 (June 11, 2020).

[7] D.20-03-028, Decision on Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning, (p. 36)

large increase in renewable facilities that California will need to meet its 2030 emissions targets.

The RPS program works in conjunction with the IRP as the primary driver to build new renewable resources that meet system needs. Originally adopted in 2002 and most recently updated by SB 100 (de Leon, 2018), the RPS program requires that the State's LSEs procure 60 percent of their total electricity retail sales from renewable energy resources by 2030. Additionally, SB 350 mandates that 65 percent of each LSE's RPS procurement must be derived from contracts of 10 or more years beginning in RPS Compliance Period 4, which will run from 2021 to 2024.[8] RPS mandates drive the build-out of new renewable resources, which helps meet GHG emission reduction targets and system reliability needs set in the IRP.

The IRP process sets an electric sector GHG reduction target and identifies an optimal portfolio of resources needed to meet that target and maintain system reliability at least-cost. Each of the CPUC's jurisdictional LSEs is required to regularly submit IRPs with the CPUC that are consistent with this portfolio. In their IRP filings, LSEs detail how they will meet GHG and reliability targets with new and existing resources. If the LSEs' IRPs collectively show actual or potential deficiencies, the CPUC may order additional procurement.

2.1.1 ESPs' Current Procurement Practices

The ESPs' current energy procurement practices are useful to consider the potential implications of reopening Direct Access on GHG emissions. Figure 3 (below) shows the energy resource mix for each class of LSE (CCA, ESP, IOU) for 2019 based on data provided to the California Energy Commission for Power Content Label (PCL) reporting purposes.[9]

The PCL data shows that, as a class, ESPs have relied heavily on purchases of unspecified system power to a much greater extent than either CCAs or IOUs. The University of California Regents, Three Phases, and Just Energy are notable exceptions, as ESPs primarily rely on contracts with renewable resources.

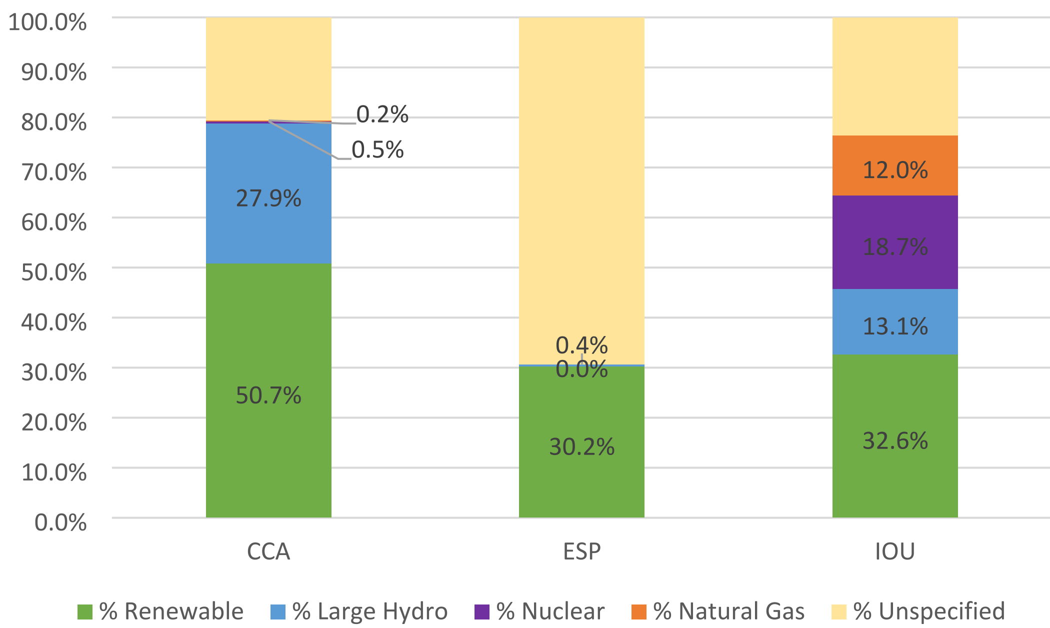
Unspecified system power refers to power purchased by LSEs on CAISO day ahead or real-time markets that cannot be tied to specific generation source. Reliance on unspecified system power, which is generally cheaper and requires no long-term contracting, has been a source of competitive advantage for ESPs by allowing them to avoid higher costs and commitments of long-term contracts. ESPs' procurement practices illustrated here also have implications for reliability as further discussed in the following section. For the purposes of GHG-emissions, unspecified system power has a similar, but slightly higher emissions profile as gas generation, indicating that it consists

[8] RPS rules measure compliance as a percentage of energy used during the entire compliance period. Failure to meet the long-term contracting procurement, however, results in failure to meet RPS requirements.

[9] Figure 3 is based on data provided for the California Energy Commission Power Content Label for 2019. A complete data set for each IOU, CCA, and ESP, including total retail sales, can be found in Appendix 1 at the end of this report. Appendix 1 presents a single overall power content for each LSE, which was calculated using weighted averages for each LSEs' various tariffs based on load share.

primarily of fossil fuel generation.[10]

Figure 3: Energy Resource Mix Used by Each LSE Class in 2019



The parties representing Direct Access have noted in comments to the Staff Draft Report that this energy resource mix is a snapshot of their procurement in 2019, and this resource mix will change as they are required to meet the RPS obligations pursuant to SB 350 and SB 100.

It should also be noted that the most recent Power Content Label available is for 2019, and there is several important changes that occur to the LSEs' Energy Resource Mix 2020-2024. First, the 2019 PCL does not incorporate any allocation of the future energy benefits being considered in the CPUC's Power Charge Indifference Adjustment (PCIA) proceeding. The IOUs' resource mix includes long-term contracts for RPS and utility-owned nuclear and hydro resources that were built for all customers, including those that have since departed for CCA and Direct Access service. The Proposed Decision issued on April 5, 2021 in the PCIA OIR (R.17-06-026) has ordered the IOUs to allocate a portion of their legacy RPS resources to LSEs that now serve those customers. As a result, a share of the renewable resources shown in the IOUs' content will be transferred to other LSEs. SCE and PG&E are also allocating portions of their legacy GHG-free portfolio (large-hydro and nuclear in Figure 3) to the LSEs. This allocation will reduce the IOU's nuclear and large-hydro positions while increasing the position of CCAs and ESPs for those resources in future PCL filings.

In light of these issues, the Energy Resource Mix does not provide a forecast of what resources will

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[10] The California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (April 2019) Section 95111(b)(1) uses an Emissions Factor for unspecified power as 0.428 MT of co2e/MWh. The U.S. Energy Information Administration estimates the carbon intensity of gas generation nationwide as 0.91 lbs/kWh, or .413 MT of co2/MWh. The Integrated Resource Planning procedure has calculated an average of 0.422 MT of Co2e/MWH for gas generation in California in 2020.

be procured if Direct Access is reopened or the resulting GHG emissions. With new policies currently recently adopted in SB 350, SB 100 and the PCIA proceeding, the LSEs' resource mix will be changing over the next several years. However, the 2019 Energy Resource Mix does illustrate the ESPs' traditional procurement practices, and that absent statutory obligations, the ESPs primarily rely on unspecified CAISO system power to meet their obligations.

2.1.2 Impact of Direct Access Expansion on setting GHG emission reduction targets in Integrated Resource Planning

The IRP process sets an electric sector GHG reduction target[11] and identifies an optimal portfolio of resources needed to meet that target and maintain system reliability at least-cost. Each of the CPUC's jurisdictional LSEs are required to regularly submit IRPs with the CPUC that are consistent with this portfolio. In their IRP filings, LSEs detail how they will meet GHG and reliability targets with new and existing resources. If the LSEs' IRPs collectively show actual or potential deficiencies, the CPUC may order additional procurement.

GHG emission reduction targets are based on the load forecast for each LSE. If Direct Access was opened to all non-residential customers, the large-scale load migration would create planning challenges for setting targets. As discussed in Section 1.5, ESPs do not have long term customer commitments, which makes load forecasting and long-term planning highly uncertain. Load may shift between various ESPs on a year-to-year basis, which means that the load that an ESP plans for today may grow or shrink, potentially significantly, in the years ahead, leaving that portion of load unplanned for when it migrates to another ESP.

Each ESP provides its own load forecast in IRP. Because ESP load is confidential, they do this without knowing the load forecast of other ESPs or how their load forecasts contribute to achieving the Direct Access cap. This led to the challenge that the sum of individually provided ESP forecasts have not added up to the total Direct Access load cap, which is the portion of load that they must plan for in IRP. If ESPs do procure based on their identified IRP needs, their collective procurement may still not add up to the aggregate ESP procurement obligation, which would cause under-procurement and jeopardize the electric sector meeting its 2030 GHG and reliability goals. The CPUC is currently able to resolve this problem because Direct Access load is capped, so the CPUC can adjust the ESPs' procurement requirements to meet the known capped load. However, if the Legislature opens more load to Direct Access, then the CPUC will no longer have a reliable forecast of the ESPs' load nor any other LSEs' load, which will make setting LSE-specific GHG reduction goals very challenging under the current framework.

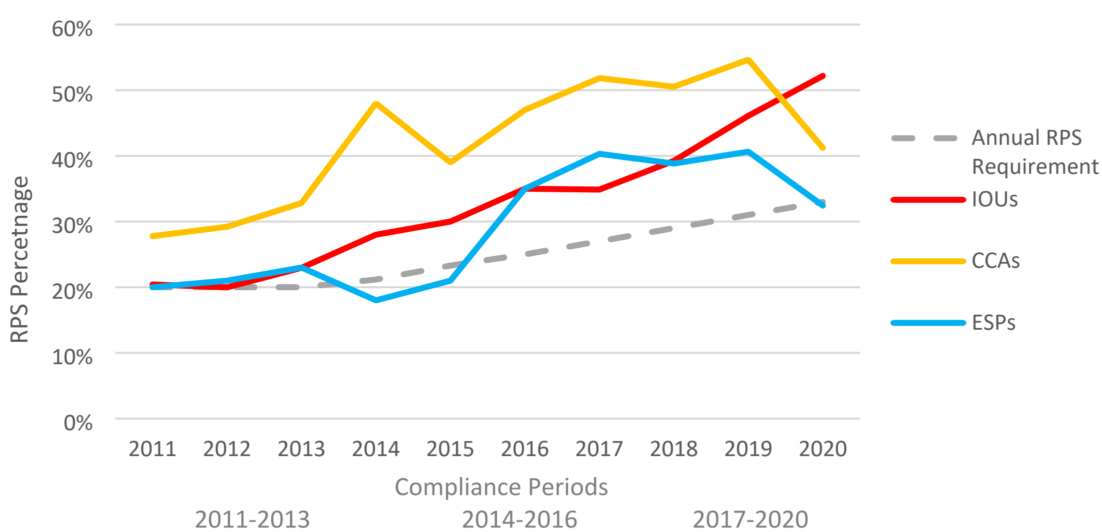
2.1.3 Direct Access Expansion and Renewables Portfolio Standard Compliance

The *2020 California Renewables Portfolio Standard Annual Report* provides a comprehensive evaluation of

[13] Electric sector GHG targets are set consistent with California Air Resources Board Scoping Plan ranges. Available: https://ww3.arb.ca.gov/cc/scopingplan/scopingplan.htm

each LSE's historical and forecasted RPS compliance positions.[12] Figure 4 shows the trend in average RPS energy as a percentage of load by IOUs, CCAs and ESPs from 2017 to 2024. The Report found that from 2017 through 2020, on average, all classes of LSE forecasted that they procured quantities of RPS above mandated RPS requirements. However, the Report found while the ESPs were forecasted to be in compliance on average, compliance verification indicates that only 7 of 14 ESPs were considered to be on track to meet their 2017-2020 compliance period requirements,[13] while eleven ESPs are considered high risk in not meeting their 2021-2024 requirements.[14] Three ESPs failed to meet RPS compliance period 2014-2016 compliance requirements.

Figure 4. Average Actual and Forecasted LSE RPS Percentages (2011-2020)[15]



The data presented in Figure 4 on RPS Compliance data from 2014 to 2020 shows that ESPs tend to procure a smaller percentage of RPS energy than IOUs or CCAs do. ESPs have an obligation to comply with the state mandated RPS requirements. However, if the past procurement indicates future outcomes, then load migration from IOUs or CCAs to ESPs may lead a net decline in RPS procurement relative to the current forecast. If a significant amount of load migrates to Direct Access, the relative decline in the procurement of RPS resources could lead to an increase in GHG emissions.

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[12] RPS requirements differ from Power Content Label since large hydro and nuclear are not RPS-eligible technologies. Furthermore, RPS rules allow for the procurement Geothermal and Biopower, which are GHG emitting.

13 "The CPUC issues its RPS compliance determinations after the CEC verifies RPS-eligible procurement from renewable energy facilities for each compliance period. Please see the CEC's RPS Verification website for more information: https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/renewables-portfolio-standard-5."

[14] 2020 California Renewables Portfolio Standard Annual Report, Section IV, Annual Compliance Reviews.

[15] See Chapter II of the 2020 RPS Annual Report to the Legislature.

2.1.4 Impact of Direct Access Expansion on Long-term Contracting to Meet GHG Emission Reductions

In the past, the IOUs were primarily responsible for building new renewable generation resources. However, IOUs will only be responsible for 50 percent of load by 2021, and the IOUs' portfolios currently include more RPS eligible resources than they need to meet RPS requirements for their current load. Meanwhile more RPS-eligible generation is still needed statewide for California to reach its 2030 GHG emission reduction targets.

SB 350 addressed the issue that other LSEs will be increasingly responsible for ensuring new RPS resources are built by requiring that all LSEs procure at least 65 percent of their RPS requirements through contracts of 10-years or longer. This requirement starts in the 2021-2024 RPS compliance period. The 10-year requirement is necessary to ensure that RPS contracts cover the capital costs needed to finance new renewable projects.

The ESPs have a limited record of entering long-term contacts. The *2020 California Renewable Portfolio Standard Annual Report* found that of the twelve ESPs that forecast serving load in the 2021-2024 compliance period, three ESPs are forecasted to have procured enough long-term RPS energy, seven have procured some long-term RPS energy, and two have not procured any long-term RPS energy to meet the 65 percent requirement.[16] While the ESPs will not need to reach the 65 percent long-term contracting requirement until 2024, they will need to make a significant investment in the near term for new renewable energy projects to come online between 2021-2024.

In informal comments to the January 8, 2020 workshop, Direct Access representatives stated that ESPs are able to meet long-term contracting requirements and are on a pathway to compliance in 2024. Specifically, Shell Energy has announced a new 200 MW solar project and Direct Energy announced a 250 MW solar project.[17] Furthermore, Shell and Commercial Energy argue that expansion of the Direct Access market will increase market liquidity and encourage LSEs to pursue long-term investments.[18]

However, the avoidance of long-term contracts has been a feature of ESPs business model to this point, as illustrated in Figure 3. First, with a few notable exceptions such as the University of California Regents and 3Phases, most ESPs have procured the minimal renewable energy required to meet California's RPS Compliance standards. Their competitive focus appears to be on minimizing procurement costs to customers. Second, customer commitments to ESPs are generally short term, creating load uncertainty for ESPs beyond on a one- or two-year horizon.

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[16] See *2020 California Renewable Portfolio Standard Annual Report*, pg. 34-35

[17] 2018 RPS Compliance Reports filed August 1, 2019 provide detail for the amount and number of long-term contracts in place by ESPs as of the date of those filings

[18] See Workshop Comments filed by Shell Energy.

2.2. Ensuring Reliability with Expansion of Direct Access

2.2.1 How the CPUC Ensures Reliability

The CPUC manages electric reliability through the Resource Adequacy (R. 17-09-020) and IRP proceedings (R.20-05-003).

The purpose of the Resource Adequacy program is to ensure that existing resources needed for reliability are kept online by requiring that CPUC jurisdictional LSEs have sufficient capacity under contract to meet their peak demand plus a 15 percent planning reserve margin. LSEs also are subject to local and flexible capacity obligations. Resource Adequacy contracts ensure the resources needed for local grid reliability and renewable integration are available. LSEs are required to make annual and monthly showings to the CPUC reflecting that they meet their system, local and flexible Resource Adequacy requirements.

The IRP proceeding manages longer-run reliability by ordering the procurement of new generation resources. The IRP identifies long-run needs by modeling system resources out to ten years to determine the level of procurement needed to meet forecasted demand. When the IRP identifies a shortfall, the CPUC may order LSEs to procure new generation resources based on those findings. In 2019, the CPUC ordered that LSEs procure 3,300 MW of additional capacity to meet the current reliability and assigned each LSE a share of the procurement obligation based on their proportion of total load.[19] More recently, the Commission in issued an assessment in R.20-05-003 of mid-term electric system reliability need for the years 2024-2026, which estimated a shortfall of approximately 7,500 MW of effective capacity by 2026 and proposes the procurement of additional resources to fill that gap.[20]

Investment in new generation benefits all customers by lowering the risks of energy shortfalls for all LSEs. However, because the costs of the investing in new resources are high and require long-term contracts and all LSEs receive the benefits, each LSE has a financial disincentive to invest in new generation. In other words, because failure to bring new resources does not result in outages for the customers of an individual LSE, but are borne by all customers, there is little direct incentive for each LSE to comply, absent a robust compliance and enforcement regime (which does not yet exist) or reliance on IOU backstop (which is not likely a viable alternative in the long-term as IOUs lose load). This creates a tendency for an unregulated market to underinvest in reliability, creating the potential for capacity shortages, as is currently the case.

2.2.2 Reliability Shortfalls Identified in Resource Adequacy and IRP

The system capacity in California and throughout the Western Electricity Coordinating Council (WECC) region is constrained, which in part led to rolling blackouts in summer 2020. The *Root*

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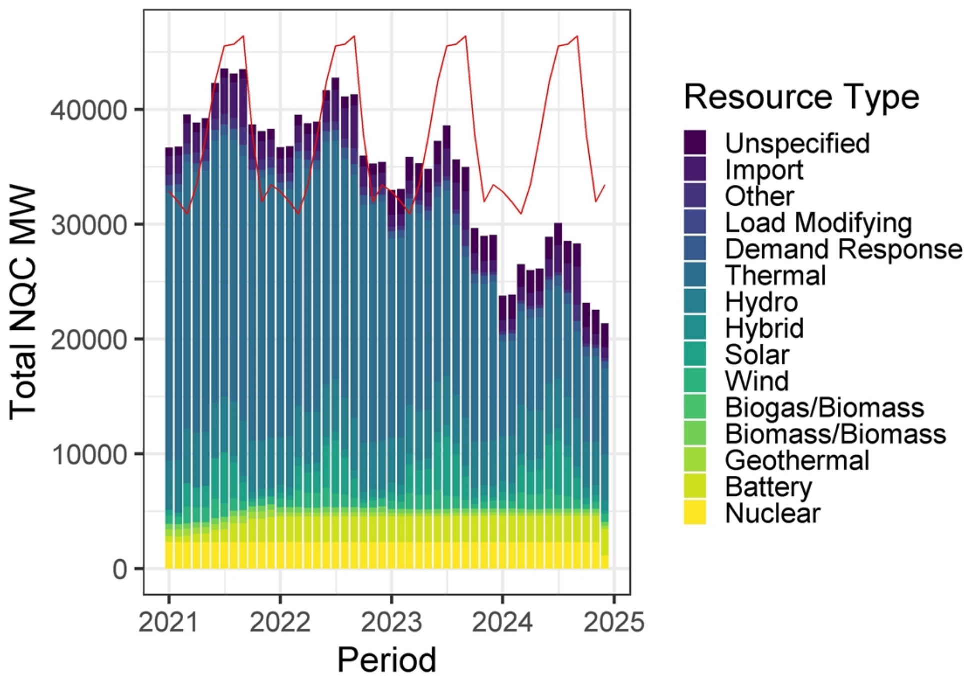
19 D. 19-11-016, Finding of Fact 5, p.68 and Ordering Paragraph 3, pp. 80-81.

20 Administrative Law Judge Ruling on Medium Term Reliability Procurement Requirements issued February 22, 2021 in R. 20-05-003.

Cause Analysis found that the Planning Reserve Margins were exceeded this past summer, verifying that the state currently has a capacity reliability shortfall and requires new generation.[21]

Figure 5 below illustrates the contracted Net Qualifying Capacity relative to maximum monthly peak load, reported by LSEs in their IRP filings. The figure indicates that capacity shortfalls are forecasted to increase in 2021 and beyond. In aggregate, LSEs have procured between about 94 and 96 percent of their 2021 system peak Resource Adequacy requirements for July through September. This 4 to 6 percent capacity shortfall could result in rolling blackouts during critical peak periods this coming summer without major efforts to secure new resources.

Figure 5. Total Net Qualifying Capacity by Month and Resource Type 2021-2024[22]



The tightening Resource Adequacy market has made it difficult and more expensive to procure Resource Adequacy contracts, particularly for newer LSEs. LSEs that fail to meet their Resource Adequacy requirements must pay citations. They will do this if there is no available Resource Adequacy capacity to procure, or the needed Resource Adequacy costs more than the citations themselves. Citations serve to penalize LSE's that fail to procure their required Resource Adequacy, but do not resolve the underlying reliability shortfall.

To meet this energy shortfall, in D.19-11-016 the CPUC ordered LSEs to procure 3,300 MW of additional capacity,[23] requiring that 50 percent of the required resources come online by August 1,

[21] Final_Root_Cause_Analysis_MidAugust_2020_ExtremeHeatWave.pdf

[22] Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009, pg. 9, can be found at 355770978.PDF (ca.gov)

23 D. 19-11-016, Finding of Fact 5, p.68 and Ordering Paragraph 3, pp. 80-81.

2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. As a stopgap measure to ensure reliability until the new generation is online, the decision recommended to the State Water Resources Board that generation contracts for several large Once Through Cooling (OTC) generators that were slated to retire by December 31, 2020, be extended through 2022.[24] CCAs and ESPs may choose to self-procure resources to meet their procurement obligations or may elect to have the IOU procure on their behalf. D.19-11-016 directed CPUC staff to develop a mechanism similar to the Cost Allocation Mechanism (CAM) used in previous procurement decisions[25] to address cost allocation associated with both LSEs that choose to opt out of self-procurement and with LSEs that opt in (to self-provide) but fail to meet their obligations.[26]

2.2.3 Challenges to Meeting Capacity Shortfalls in a Disaggregated Market

The 2019 IRP decision (D.19-11-016) was the first time that the CPUC ordered non-IOU LSEs to directly procure new generation capacity. It represents a test of whether individual LSEs in a competitive, disaggregated market can effectively procure the resources needed to meet their long-term reliability obligations and it will be doing so at a time when vast quantities of resources will be needed to replace aging facilities, including steam generation, large nuclear plants, combined heat and power and other qualifying facilities falling off of long-term contracts. Reopening Direct Access raises several concerns for the CPUC.

First, it unclear whether this disaggregated procurement will result in an optimal and cost-effective means of meeting California's GHG reduction and system reliability needs. 20 LSEs conducting separate procurement cannot achieve the lower costs from economies of scale, and it is unclear whether these separate procurements will, in aggregate, meet system needs. As stated in D.19-11-016, this procurement order will "test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP."[27]

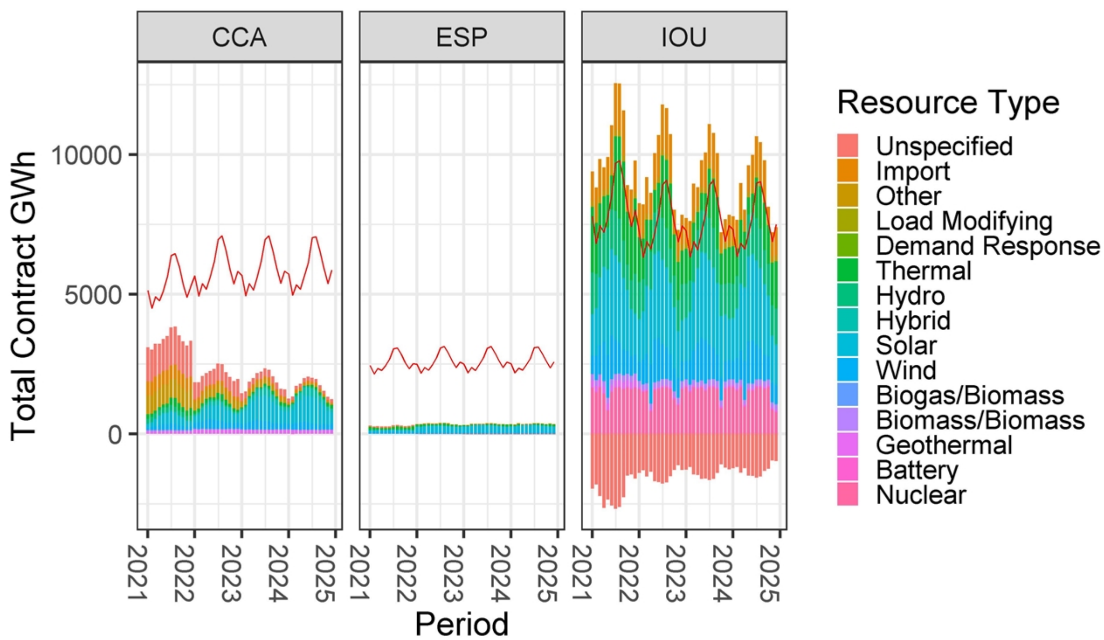
Second, load migration makes it difficult for all LSEs to accurately forecast load and therefore to sign the long-term contracts needed to finance new resource development. In their informal comments to the January 8, 2020 workshop, CalCCA expressed significant concerns with the impact that significant load migration would have on their financial viability in a competitive market. CalCCA states that "The mismatch between the duration developers need in a contract for a new project, and the length of time an LSE can be confident of having a given load at a given price is a structural impediment to new project development in any market with retail competition." As CalCCA clarifies, PPAs for new construction are long duration, generally fifteen years or more, and a developer needs to know its counterparty will be able to stand behind a PPA for that duration of the contract. Under a full DA expansion, CCAs could lose a significant percentage of load, which

24 D. 19-11-016, Ordering Paragraph 1, pp. 79-80.
25 The Cost Allocation Mechanism (CAM) is a regulatory process for allocating the capacity costs of utility procurement across all benefiting customers. It was first adopted in D. 06-07-029 and has been used in multiple procurement decision since.
26D. 19-11-016, Ordering Paragraph 5, p. 82.
27 D.19-11-016 at 39

threatens to undermine the long-term contracts that CCAs have already entered and make it difficult for them to secure financing for future contracts.

Third, Figure 6 below demonstrates that ESPs have not taken an active role in ensuring that the resources are available and online to ensure system reliability. They have primarily purchased in energy in the short-term market. Figure 6 compares the amount of current and forecast load for CCAs, ESPs, and IOUs to the amount of energy they currently have under contract. The red line represents the load each LSE type currently serves. The colored bars represent the resources each LSE type has under contract. The white space between the red line and the colored bars represents each LSE class's open energy position, the amount of load that LSEs will have to serve that they have not currently contracted for.[28]

Figure 6. Total Contracted GWh each month by resource type and LSE Type, 2021-2024.[29]



While AReM, DACC and representatives of the Direct Access industry have stated in comments that they can and will meet all long-term contracting and reliability requirements, they have not to

[28] It should be noted that a certain portion of the IOU contracted resources were legacy RPS resources that the Proposed Decision mailed on April 5, 2021 has directed the IOUs to allocate to the other LSES, which will change the relative amount of contracted energy attributed to each type of LSE. However, while allocating a portion of the IOU's RPS procurement to CCAs and ESPs will pass credit for some long-term contracts to CCAs and ESPs, the allocation does not change the fact that the long-term contracts were signed by IOUs on behalf of customers who have since departed IOU service, and not by the LSEs that currently serve them.

[29] California Public Utilities Commission, Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009, December 18, 2020, available at [355770978.PDF (ca.gov)](355770978.PDF (ca.gov))

date met a procurement obligation with the level of long-term contracting that is necessary to ensure system reliability.

Finally, the ESPs' procurement processes lack transparency when compared to IOUs' and CCAs' procurement processes. IOUs receive up-front authorization from the CPUC for their bundled procurement plans and submit all procurement contracts to the CPUC for review and approval. The CPUC does not approve CCA procurements, but each CCA's procurement plans are reviewed by their Boards at public meetings and agenda packets containing details of procurement transactions are published on their public websites. In contrast, ESPs generally do not make information on their procurement available to the public and have, in the past, claimed privilege and confidentiality to avoid disclosing information to the CPUC. This lack of transparency makes it more difficult for the CPUC to monitor progress of ESP procurement activities prior to procurement deadlines and propose remedies if it seems likely that an ESP will fail to meet its obligations.

2.2.4 Mechanisms Under Development to Address Reliability in a Disaggregated Market

The CPUC is currently considering new procurement and cost allocation mechanisms in the IRP and Resource Adequacy proceedings that could solve the challenges of meeting reliability requirements in a fragmented energy market. As discussed in Section 2.3.2, the most recent IRP procurement directed in D.19-11-016 has allowed LSEs to self-procure, while also directing the development a CAM-like mechanism for LSEs that opt out or fail to meet their procurement obligation. D.19-11-016 creates a backstop procurement mechanism to be conducted by the IOU on behalf of LSEs that fail to self-provide may come at a higher cost. It remains to be seen whether a backstop procurement mechanism can deliver generation resources quickly enough to avoid near-term system reliability issues.

In the Resource Adequacy proceeding (R. 17-09-020), the CPUC is currently considering new structures to ensure reliability despite the load uncertainty that characterizes the current market. D.18-06-030 determined that multi-year local Resource Adequacy should be procured through a central buyer that will purchase all local Resource Adequacy contracts on behalf of all LSEs. D.20-02-006 directed PG&E and SCE to act as centralized procurements for Local Resource Adequacy in their respective service territories.

While central procurement has only been adopted for local Resource Adequacy,[30] a broader use of centralized procurement might be an effective way to overcome the challenges identified above related to load migration as these affect other kinds of procurement as well. However, the central buyer concept is a new, and the mechanism's efficacy is currently be examined.

[30] D.20-06-002, Ordering Paragraph 3, p. 91.

2.3. Ensuring Direct Access Expansion Does Not Result in Cost Shifting to Bundled Customers

P.U. Code Sections 366.1(d) applicable to Direct Access and CCA Customers and 366.2 applicable to CCAs require that customers leaving IOU bundled service do not burden remaining customers with stranded costs that were incurred to serve them. To ensure that bundled customers remain indifferent to the cost of load departures, CCA and Direct Access customers are required to pay the Power Charge Indifference Adjustment (PCIA) for the "stranded" or above market costs of resources procured by the IOUs on their behalf before they departed. The PCIA is intended to capture the largest potential cost-shifts between bundled and unbundled customers.

In 2018 and 2019, the CPUC refined the PCIA methodology,[31] adding mechanisms to cap the annual increase of the PCIA charge and to adjust the PCIA charge to reflect actual market prices for Resource Adequacy and RPS resources. The CPUC continues to consider further methods to fairly allocate costs and resources through Phase 2 of the PCIA Rulemaking (R.17-06-026). If Direct Access is expanded to more nonresidential customers, the PCIA refinements that the CPUC has already adopted and is still considering should address most of the cost-shifting concerns related to stranded investments in resources. However, in Sections 2.4.1 and 2.4.2 below, we consider other classes of potential cost shifts that are not addressed by the PCIA.

2.3.1 Impact of Load Migration on Energy Prices

The energy and capacity shortfalls that were discussed in Section 2.2 create conditions for generators to exercise market power and drive up the cost of energy. California has experienced a significant increase in energy prices due to the tightening of the market since 2018, which will be exacerbated if LSEs fail to secure procurement for new generation. As shown in Figure 3, ESPs are largely relying on system power, and not entering into energy contracts that hedge future energy prices. Following the energy crisis of 2000-2001, the CPUC determined that long-term contracting was necessary in order to stabilize the energy markets because it ensures that enough energy will be available in the market, which benefits all customers. Overreliance on the day ahead market leaves all customers exposed to price volatility if the market dynamics shift quickly.

The reliability challenges that California is currently facing puts under-hedged LSEs into financially vulnerable positions, which load migration could exacerbate. Significant loss of load may leave LSEs with financial commitments for new generation projects for which the LSE can no longer collect enough revenue to recover the costs, leaving LSEs and their new projects financially vulnerable.

Furthermore, if market dynamics change, non-IOU LSEs can return customers to the IOU as the provider of last resort. While P.U. Code 367.7 and subsequent legislation and decisions[32] require that there is no cost shifting to existing bundled customers – the reality is that if the capacity and/or

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[31] See D.18-10-019 and D.19-10-001.

[32] See D.13-01-021

energy market increase precipitously, as occurred during the energy crisis, the IOUs will not be hedged for the returning customers and could potentially need to pay high spot market prices, to the detriment of all customers and the stability of the market. Shortfalls in committed resource capacity drives up prices for all customers.

2.3.2 Load Migration May Lead to Cost Shifting within Customer Classes

IOU tariffs group customers into different rate classes based on similar characteristics to serve that class. Despite recent reforms to rate structures such as the limited adoption of time of use rates, tariffs do not perfectly reflect the cost of serving each individual customer in that rate class. Rather, each IOU tariff class includes customers that have more attractive load-profiles, and thus are less expensive to serve, and other customers with load-profiles that are more costly to serve. When customers with a different cost to serve all pay the same rate, the low cost of service customers are essentially subsidizing those who are more expensive to serve.

Direct Access expansion could lead to cost shifting by changing the composition of customers within each rate class. This could occur if customers with a lower cost of service have an economic incentive to depart IOU service, leaving the IOUs with customers with a higher average cost-of-service. If such migration were to occur, it would change the composition of IOU tariff classes, leaving the IOUs with a pool of higher cost customers. To cover the higher average cost of serving the remaining pool of customers, IOUs would need to increase their rates for affected rate classes.

2.4. Impact on Criteria Air Pollution and Toxic Air Contaminants

The Federal Clean Air Act requires the Environmental Protection Agency (EPA) to establish National Ambient Air Quality Standards (NAAQS) for the maximum allowable concentrations of six "criteria" pollutants in outdoor air to protect public health: carbon monoxide, lead, ground-level ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.

The CPUC has very limited jurisdiction over the emission of criteria pollutants and toxic air pollutants.[33] CPUC jurisdiction consists of setting emission standards for criteria air pollutants related to IOU-owned Biomass facilities. The CPUC minimizes the emission of criteria air pollutants through the requirements established by Senate Bill (SB) (2019, De Leon), which, in addition to setting more ambitious RPS goals, requires that the State "Reduc[e] air pollution, particularly criteria pollutant emissions and toxic air contaminants." Additionally, the CPUC requires that LSEs "minimize localized air pollutants" in their Integrated Resource Plans.

[33]Clean Air Act permitting is the shared responsibility of the California Air Resources Board (CARB), its 35 air pollution control agencies (districts), and EPA Region 9. California's 35 local Air Pollution Control Districts or Air Quality Management Districts are responsible for regional air quality planning, monitoring, and stationary source and facility permitting. The Air Quality Management Districts are responsible for the monitoring the criteria air pollutants emitted by California electricity generators

The CPUC's ability to assess the impact of expansion of Direct Access on criteria and toxic pollutants is limited by the fact that most emissions in the state's electric system occur as the result of unspecified transactions in the CAISO energy market. These unspecified energy purchases are not tied to a specific generator or even resource type. However, as was discussed in Section 2.1.1 and illustrated in Figure 3, unspecified purchases primarily consist of power generated by gas power plants across the WECC and is virtually identical to gas generation in terms of its emissions profile. While it is not feasible to calculate the criteria air pollutants for each LSE, it can be reasonably concluded that air pollutant levels would be higher if LSEs primarily procure unspecified power rather than power from specified carbon-free resources through long-term renewable contracts.

As discussed in Section 2.1.4, new RPS standards require that LSEs procure 65 percent of their RPS through contracts of 10 years or more, and primarily from in-state resources. The new compliance requirements adopted in RPS and IRP require ESPs to shift toward a greener portfolio is anticipated to decrease criteria pollutants emissions for ESP procurement. However, if they continue to rely on system power, and lag behind CCAs and IOUs in their adoption in long-term RPS contracts, then the net impact of Direct Access expansion will be to increase the criteria pollutants emission relative to emissions if Direct Access was not expanded. Staff anticipate that ESPs will continue to rely on unspecified energy procurement to the extent they can. If Direct Access is further opened and ESPs continue their current practice of relying on unspecified power as a significant source of their procurement, it will lead to an increase in criteria air pollutants.

3. Conclusions on the Assessment to Reopen Direct Access

In conclusion, Staff's assessment of the impacts of reopening Direct Access pursuant to P.U. Code 365.1 is summarized as follows:

- Large-scale generation resources are needed because the state has a major capacity shortfall over the next decade. The CPUC has ordered 3300 MW of new generation to be built by 2023 and proposed another roughly 7500 MW by 2026. The state needs to build nearly 25,000 MW of new GHG-free resources, including over 12,000 MW of storage, by 2030.

- The load migration that would be enabled by reopening Direct Access leaves all LSEs uncertain about future load, making it challenging for any LSE, including the CCAs and IOUs, to build the large-scale generation resources the state needs to ensure reliability in the future.

- 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.

- If the past procurement indicates future outcomes, then load migration from IOUs or CCAs to ESPs may lead a net decline in RPS procurement, which may impact GHG emissions and increase criteria air pollutants and toxic air contaminants, relative to maintain the current cap on Direct Access.

- Shortfall in generation capacity drives up the cost of energy for all customers adversely impacting all ratepayers.

Appendix 1: *2019 LSE Specific PCL Data*[34]

[34] This table is based on 2019 PCL data provided by the CEC on February 2nd. LSEs may file a different PCL for each offered rate and assigning specific resources to different tariffs. For those LSEs that filed multiple PCL's, we used a weighted average based to calculate a single PCL for each LSE.

LSE	Type	Total Retail Sales (MWh)	% Renewable	% Large Hydro	% Natural Gas	% Nuclear	% Other	% Unspecified
Clean Power Alliance	CCA	8,986,112	51%	8%	0%	0%	0%	41%
EBCE	CCA	5,821,428	63%	25%	0%	1%	0%	11%
Marin Clean Energy	CCA	5,136,159	61%	28%	0%	1%	0%	9%
Silicon Valley Clean Energy	CCA	3,983,497	48%	52%	0%	0%	0%	0%
Peninsula Clean Energy	CCA	3,569,458	56%	34%	0%	1%	0%	9%
San Jose Clean Power	CCA	3,453,134	35%	29%	0%	1%	1%	35%
Clean Power SF	CCA	2,705,871	51%	45%	2%	0%	0%	2%
Sonoma Clean Power	CCA	2,360,421	51%	46%	0%	0%	0%	3%
Pioneer Community Energy	CCA	1,089,009	30%	0%	0%	0%	0%	70%
Valley Clean Energy Alliance	CCA	642,652	45%	31%	0%	0%	0%	23%
Redwood Coast	CCA	636,033	43%	55%	0%	0%	1%	1%
Lancaster Choice	CCA	545,556	29%	44%	0%	0%	0%	27%
Monterey Community Energy	CCA	545,556	29%	44%				27%
Rancho Mirage EA	CCA	273,406	35%	18%	0%	0%	0%	46%
Apple Valley	CCA	234,589	28%	0%	0%	0%	0%	72%
Pico Revera	CCA	212,060	29%	0%	0%	0%	0%	71%
San Jacinto	CCA	159,170	31%	0%	0%	0%	0%	69%
Solana Energy Alliance	CCA	60,277	51%	49%	0%	0%	0%	0%
King City Community Power	CCA	37,886	28%	0%	0%	0%	0%	72%
Desert Community Energy	CCA							
Constellation	ESP	6,388,304	25%	0%	0%	0%	0%	75%
Shell Energy	ESP	5,534,319	28%	0%	0%	0%	0%	72%
Calpine Energy Solutions	ESP	4,140,896	31%	0%	0%	0%	0%	69%
Direct Energy	ESP	2,742,547	29%	0%	0%	0%	0%	71%
Calpine Power America	ESP	1,438,442	36%	0%	0%	0%	0%	64%
Pilot Power Group	ESP	1,328,720	29%	0%	0%	0%	0%	71%
EDF	ESP	905,114	43%	0%	0%	0%	0%	57%
3 Phases	ESP	465,486	90%	0%	0%	0%	0%	10%
UC Regents	ESP	253,553	47%	39%	0%	0%	0%	14%
Commercial Energy	ESP	88,429	10%	0%	0%	0%	0%	90%
Tiger	ESP	3,511	0%	0%	0%	0%	0%	100%
SCE	IOU	61,582,648	35%	8%	16%	8%	0%	33%
PG&E	IOU	36,035,348	29%	27%	0%	44%	0%	0%
SDG&E	IOU	14,534,167	32%	0%	24%	0%	0%	44%

(END OF APPENDIX A)