Report Providing Recommendations on the Schedule to Reopen Direct Access

California Public Utilities Commission Staff Report

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

September 28, 2020

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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 Resource 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

Executive Summary

In 2018 the Legislature approved Senate Bill (SB) 237 (Hertzberg), which 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; 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 Access 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)(1) for the Legislature's consideration in its determination of further reopening. Should the Legislature elect to enact a further reopening of Direct Access, this report provides recommendations for the schedule of actions that should occur prior to the reopening, consistent with these provisions. In this document, the California Public Utilities Commission's (CPUC) Energy Division staff presents recommendations for the schedule. CPUC Energy Division staff recommends the following:

Prior to Further Direct Access Reopening:

Staff recommends that reopening be conditioned on ESPs' demonstrated compliance with the following obligations:

- 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.
- ESPs comply with all Resource Adequacy (RA) requirements including multi-year local, year ahead flexible and system, and month ahead system and flexible obligations.

Recommended Schedule if Direct Access is Reopened:

If the Legislature directs further reopening of nonresidential Direct Access, the legislation should allow the CPUC to:

- Set an initial re-opening schedule in increments equal to 10 percent of eligible non-residential load per year.
- Condition each annual expansion on CPUC review and approval of compliance with IRP, RA and RPS requirements, as subject to CPUC approval.
- Order annual expansion to take place on a schedule that will allow Load Serving Entities (LSEs) the ability to fully comply with RA requirements.

Staff suggests that a re-opening schedule that raises the Direct Access cap by 10 percent of non-residential load per year should minimize planning disruptions associated with load departure and allow the CPUC and market actors sufficient time to develop the regulatory and market structures needed to ensure long-term resource development in a fragmented retail market.

Recommendations for Legislative Action:

If the Legislature establishes a schedule to reopen Direct Access to all non-residential customers, CPUC staff recommends that the following legislative actions be considered to ensure that the greenhouse gas (GHG) emissions, reliability and cost shifting provisions of SB 237 are met:

- Provide clear authority to enforce compliance with IRP GHG goals by all LSEs subject to P.U. Code Section 454.52 (b).

- Ensure that the CPUC continues to have clear authority to enforce the State's Resource Adequacy goals defined in P.U. Code Section 380.

- Amend P.U. Code Section 949.25 to provide the CPUC with the authority to revoke ESP licenses and CCA registration for repeated non-compliance with RA, RPS or IRP requirements.

- Consider provisions to ensure that no cost shifting as the result of customer moving between different Load Serving Entities (Electric Corporations, Community Choice Aggregators (CCAs), and ESPs) are applied equitable to all customers.

1. Introduction

1.1 Objectives and Scope

Pursuant to Senate Bill (SB) 237 (Hertzberg, 2018), the CPUC is required to provide the Legislature with recommendations on the further reopening of Direct Access, which is also referred to as direct transactions. 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.

The intent of this Staff Report is to provide 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. Should the Legislature elect to enact a further reopening of Direct Access, this report provides recommendations for the schedule of actions that should occur prior to the reopening, consistent with these provisions.

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 non-residential customers may purchase electricity from a competitive non-utility entity called an Electric Service Provider (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 Community Choice Aggregators (CCAs) will account for approximately 29 percent of load in Investor Owned Utility (IOU) territory.

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

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 14 percent of load in IOU service territory and is projected to increase to over 16 percent by 2021 with the implementation SB 237. 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 and 2022 with the 4,000 GWh increase allowed by SB 237.

Figure 1: 2021 Direct Access Load and Eligible Direct Access Load

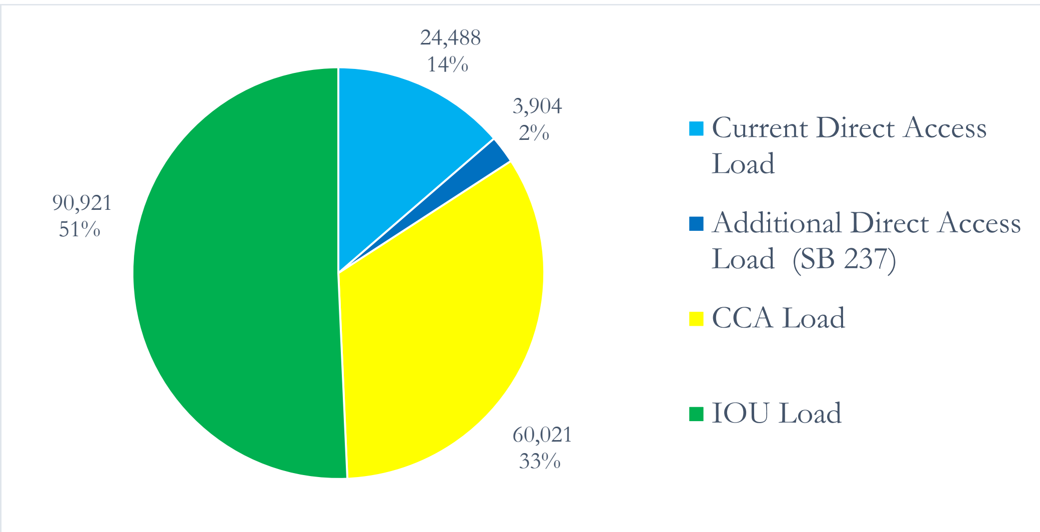
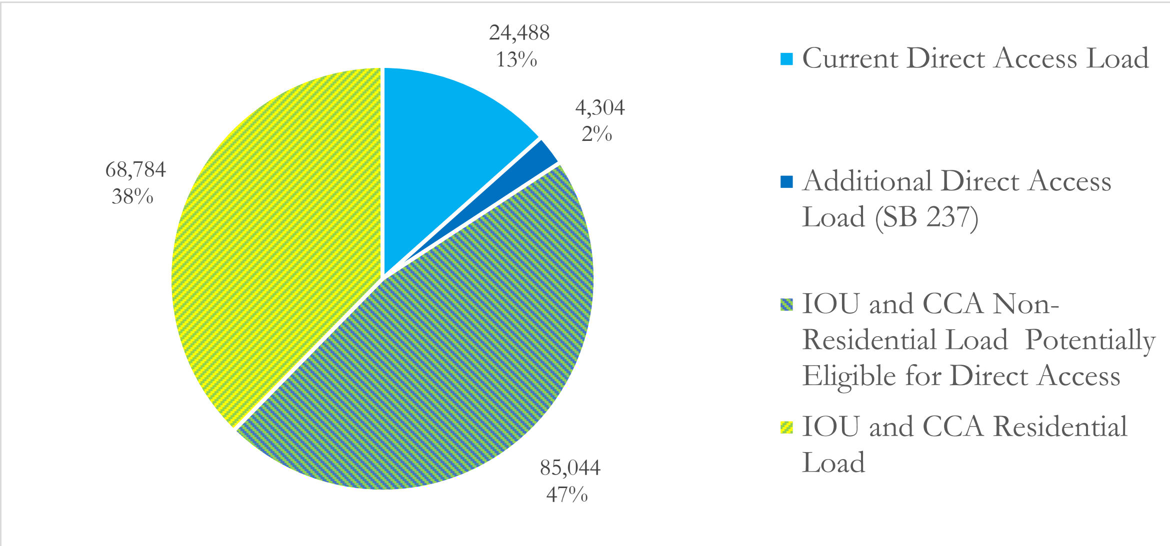


Figure 2 shows current Direct Access load and the additional load that could become eligible for Direct Access pursuant to SB 237. As Figure 2 shows, 47 percent of the current IOU and CCA load could move to Direct Access if the Legislature decides to re-open the entire non-residential market to Direct Access, as contemplated in SB 237. The 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.



1.2 Background on Direct Access and Retail Choice

Direct Access was originally adopted in 1996 as part of California's Electric Utility Industry Restructuring Act, 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 offered retail choice to customers by allowing them to purchase electricity directly from an ESP while the IOUs continued 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, 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 using Direct Access and 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, roughly 13% of total load.

In 2002, AB 117[3] established P.U. Code Section 331.1, which authorizes the implementation of Community Choice Aggregation. 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 by load share. To provide sufficient time for ESPs to comply with current year-ahead Resource Adequacy requirements, the implementation of additional Direct Access load will not occur until January 1, 2021. In Phase 2 of R.19-03-009, the CPUC is addressing SB 237's requirement that Energy Division provide recommendations to the Legislature on further reopening of non-residential Direct Access.

Since 2001, the Legislature and the CPUC have implemented a series of new regulations to ensure there is sufficient generation capacity available for system reliability that have created new obligations for ESPs. Among the key requirements adopted were the creation of long-term and short-term procurement requirements for Load Serving Entities (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 renewables 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 emissions reductions goals in a single proceeding and seeks to define an optimal path for realizing both goals.

1.2.1 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 California can simultaneously create more market choice for

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

consumers, meet 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.

The Action Plan identified a list of policy areas and relevant proceedings that would be impacted by the expansion of retail choice. Some of these topics are relevant to the provisions required by SB 237 regarding a recommendation for Direct Access expansion. This report is informed by, and expands upon, the analysis of these topics in the Action Plan.

1. **Disclosure of Green House Gas (GHG) and Renewables Content for use in LSE Electricity Portfolios[4]:**

   The Action Plan raises the issue that consumers lack transparency into the power content of electricity sold by LSEs and identifies the need for clear disclosures for GHG emissions and Renewables Content from all LSEs. The California Energy Commission (CEC) provides "Power Content Labeling" and AB 1110 (Ting, 2016) requires that the CEC amend the Power Source Disclosure (PSD) to include GHG emissions intensity factors and guidance for disclosure of unbundled Renewable Energy Credits (RECs) beginning in 2020 for the 2019 calendar year.

   The Action Plan recommended that there be disclosure for all power content, including imports and unbundled RECs.

2. **Resource Adequacy[5]:**

   The Action Plan identifies challenges to maintaining adequate electric capacity to ensure reliability caused by structural changes to the energy market. These challenges include: the increasing use of intermittent renewable resources; the upcoming retirement of natural gas power plants due to once through cooling requirements; retirement requests from generators; and the rapid expansion of CCAs resulting in customer load migration. A competitive electricity market structure may cause uncertainty for market participants who must procure capacity for an unknown amount of load and generators who must now sell generation to new market entrants. Since publication of the Action Plan, R.17-09-020 has considered refinements to the Resource Adequacy program. This work is ongoing. Load migration and load fragmentation continue to create complex issues for electric system reliability that this Staff report will explore.

3. **Contracting for Reliability and Renewable Resource Requirements[6]:**

4 California Customer Choice Project: Choice Action Plan and Gap Analysis, December 2018, p. 27-28
5 Ibid. p. 50-53
6 Ibid. p. 57-61

> The Action Plan highlights the concern over resource procurement that is necessary for the state's long-term energy supply, particularly new renewable energy resources, noting that some LSEs rely almost exclusively on short-term contracts to meet energy needs. The CPUC uses the IRP process to evaluate the state's long-term contracting requirements to meet both its reliability and renewable procurement. Each LSE is required to file its own IRP with the CPUC so that the CPUC can ensure the that it will meet its obligations; however, the IRP process is relatively new and the CPUC still in the process of developing the needed compliance tools. The Action Plan also suggests potential solutions to address reliability and resource challenges with retail choice, including coordinated multi-party procurement and the creation of a central procurement entity.[7]

The remaining topics in the Action Plan are not within the scope of SB 237 and will not be assessed in this report, although they still need to be considered within their respective proceedings.

1.2.2 Public Input to Support Staff Report Recommendations

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 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 & Electric (PG&E), Public Advocates Office (CalPA), Renewable Energy Buyers Alliance (REBA), Southern California Edison (SCE), The Utility Ratepayer Network (TURN). This report was informed by the comments and analysis of the participating parties, as well as past staff reports and decisions, which are cited below.

1.3 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.

1.3.1 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, subscription to the Direct Access program has always been at the cap 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.[8] 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.

[7] California Customer Choice Project: Choice Action Plan and Gap Analysis, December 2018, p. 62.
[8] 2018 Direct Access Lottery Enrollment Report

1.3.2 ESPs can tailor their service to customer needs

Companies seek Direct Access for various reasons. First, while the CPUC has no visibility into the rates ESPs charge their customers, it appears that ESPs 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 cheaper electricity could lead them to consider moving energy-intensive production activities out of California. Direct Access may provide these customers an incentive to keep production 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.

1.4 Challenges of Expanding Direct Access

Large-scale load migration between LSEs may 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. Modeling in the 2019-2020 IRP cycle indicates a need for nearly 25,000 megawatts (MW) of new energy resources to be built by 2030. Accomplishing this rate of new build requires either that LSEs make long-term contracting commitments or that another entity do so on their behalf.

ESPs currently procure much of their energy in day-ahead and real-time markets or through short-term contracts and have little track record of signing long-term contracts. Because Direct Access customers make short term commitments to an ESP, generally signing 1 to 2-year contracts, multi-year contracts are risky for ESPs. However, since long-term contracts are needed to meet system reliability needs and develop new clean energy resources, expanding Direct Access increases the risks for long-term procurement contracting needed to meet system reliability and GHG reduction targets.

It is important to acknowledge that, to a certain degree, these long-term 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 8th 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.

A rapid expansion of Direct Access is likely to exacerbate 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 a small amount of load returning to IOUs or migrating to ESPs, to the extent allowed by the current cap. This migration has created planning challenges but has generally proven manageable. However, a rapid expansion of Direct Access would significantly increase the medium to long term planning uncertainty because customers may freely migrate between IOUs, CCAs and Direct Access providers. This increased load migration will make long-term procurement far more challenging for all LSEs. We describe those challenges further in Section 2.

1.4.1 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.[9] The CPUC has recently adopted central procurement for local Resource Adequacy in two IOU territories—Pacific Gas & Electric (PG&E) and Southern California Edison (SCE)—to be implemented beginning in 2023.[10]

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. However, currently these market-based approaches either do not currently exist or are in the very early stages of development.

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 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.

[9] California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August, 2018), p. 65.
[10] Decision (D.) 20-06-002 (June 11, 2020).

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

Under SB 32 (Pavley, 2016) the State must reduce GHG emission 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 (IRP) for LSEs under its jurisdiction.

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 IRP filings 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' IRP filings collectively show actual or potential deficiencies, the CPUC may order additional procurement.

The Renewables Portfolio Standards (RPS) program works in conjunction with the IRP as the primary driver to build new renewable resources. Originally adopted in 2002 and most recently updated by SB 100 (de Leon, 2018), the RPS program requires that the 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.[12] RPS mandates drive the build-out new renewable resources, which helps meet GHG emission reduction targets and system reliability needs set in the IRP.

To assess the impact of Direct Access expansion to all non-residential customers on GHG emissions, we evaluate the ESPs' current planning, procurement practices, and compliance with IRP and RPS requirements, and what they indicate about ESPs' likely market behavior in the future. We also consider the implications of additional load migration and Direct Access customers' short-term commitments to their ESP on the State's ability to accurately set and meet GHG reduction targets.

2.1.1 ESPs' Current Procurement Practices

ESPs' current energy procurement practices offer the best available indication of potential impacts of reopening Direct Access on GHG emissions. Figure 3 (below) shows each LSE's 2018 power content as reported to the CEC in 2018. The green wedge in Figure 3 shows the RPS eligible resources purchased by each LSE. The dark blue represents large hydro which, like nuclear (purple), is not RPS eligible but does qualify as GHG-free according to Power Content Labeling rules. The

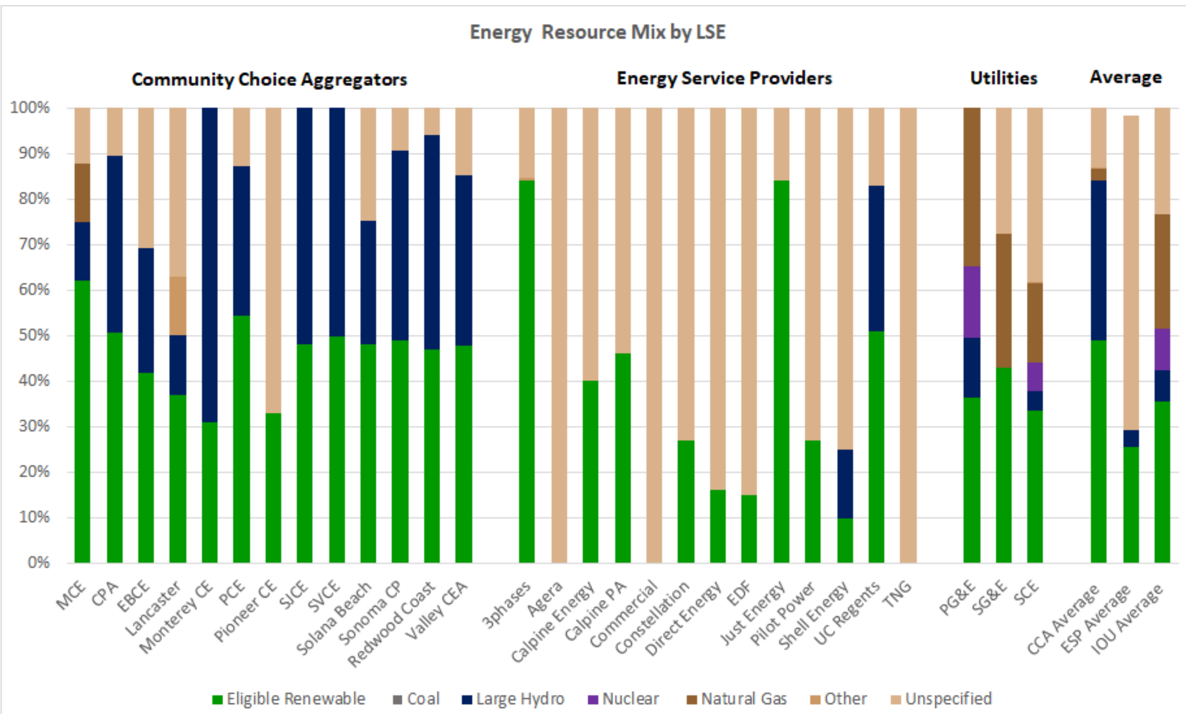
11 Electric sector GHG targets are set consistent with California Air Resources Board Scoping Plan ranges. Available: https://ww3.arb.ca.gov/cc/scopingplan/scopingplan.htm

12 RPS rules measure compliance as a percentage of energy used during the entire compliance period. This means that an LSE could fail to procure 65 percent of its RPS through 10-year or longer contracts but still meet program requirements if 65 of the RPS it procures during the 4 year compliance period comes from 10-year or longer contracts.

dark brown represents gas generation, while the lighter beige represents California Independent System Operator (CAISO) system power.

Figure 3 indicates that ESPs relied heavily on purchases of unspecified CAISO system power, with the exception of 3 Phases and the University of California (UC). This contrasts with the majority of CCAs, who procured large amounts of renewable and GHG-free resources and with the IOUs, who also outperformed ESPs in procuring GHG free energy. Unspecified CAISO system power, which includes energy from all resources including RPS eligible and gas generation, accounted for 69 percent of the ESPs' portfolio content.[13] Reliance on CAISO 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.

Figure 3: GHG free and System Power Used by each LSE[14]



ESP representatives have explained that the different resource mixes they procure reflect the differing priorities of their commercial customers. Some customers prioritize GHG emission reductions above energy prices and vice versa.[15] However, overall, the ESPs' general procurement

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[13] For a full description of each LSE's power content label report for 2018, see Appendix 2 of this report.

[14] This chart is based on California Energy Commission Power Content Label data for 2018. A complete data set for each IOU, CCA, and ESP, including total retail sales, can be found in Appendix 2 at the end of this report.

[15] Informal Comments of the Alliance for Retail Energy Markets on the January 8, 2020 Workshop, p. 3.

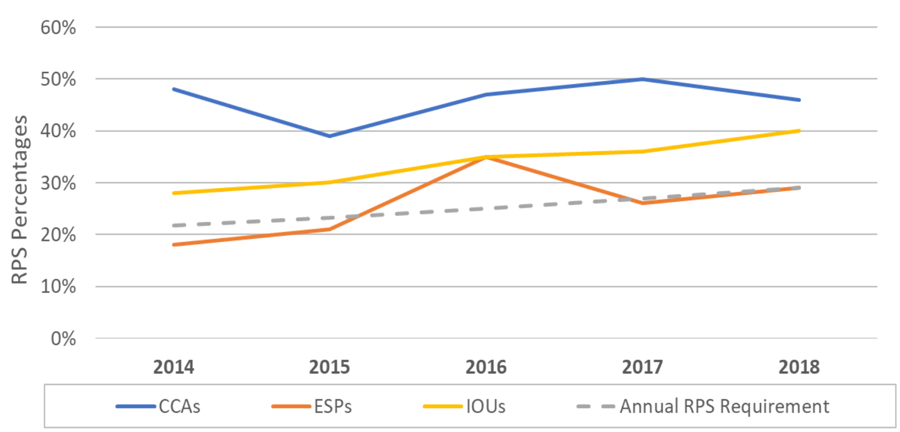
strategies, including a heavy reliance on CAISO system power, appear to increase GHG emissions relative to portfolios that rely on high amounts of RPS eligible resources.[16]

As will be further discussed in Section 2.1.4 (below) SB 350 requires all LSEs to procure a minimum 65 percent of their RPS compliance requirement with contracts of 10-years or longer starting in 2021. The ESPs' ability to comply with these requirements is untested to date. Based on past procurement trends, CPUC staff has concerns that some ESPs may not meet the new requirements.

2.1.2 Renewable Portfolio Standard Compliance

The *2019 California Renewables Portfolio Standard Annual Report* provides a comprehensive evaluation of each LSE's RPS compliance.[17] Figure 4 shows the trend in average RPS energy as a percentage of load by IOUs, CCAs and ESPs from 2014 to 2018. During this period, both CCAs and IOUs, on average, procured quantities of RPS well above mandated RPS requirements. In contrast, ESPs generally met their RPS requirements, but RPS represented a lower percentage of their procurement than it was for other LSE classes. The *2019 California Renewables Portfolio Standard Annual Report* found that while one ESP exceeded its target by more than 10 percent, the remaining 11 met or barely exceeded their RPS compliance target. 3 ESPs failed to meet RPS Period 2 (2014-16) RPS compliance targets.[18]

Figure 4. Average Actual LSE RPS Percentages (2014-2018)[19]



If the trends shown in Figure 4 are indicative of future practices, then load migration from IOUs or

[16] The GHG content of CAISO system power varies from month-to-month and hour-to-hour depending on the availability of renewable resources. Emissions information can be found at the CAISO website.

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

[18] 2019 California Renewables Portfolio Standard Annual Report, p. 25.

[19] From CalCCA's informal comments on Energy Division's January 8, 2020 workshop, p. 5, sent to the R.19-03-009 service list on January 21, 2020. Source data is from 2019 California Renewables Portfolio Standard Annual Report

CCAs to ESPs will likely lead to a net decline in RPS procurement since ESPs tend to procure proportionally less RPS resources than the CCAs and IOUs. Although RPS procurement is not precisely correlated with GHG reductions, a decline in the procurement of RPS resources would likely lead to an increase in GHG emissions.

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

The IRP process is a critical planning tool to reduce GHG emissions. The process starts by forecasting of long-term demand for each LSE. These LSE-specific demand forecasts are derived from CEC analysis in the *Integrated Energy Policy Report* (IEPR). The forecasts are adjusted to reflect near-term load migration, which is projected based on historical sales. However, while the IEPR sets targets for each IOU and CCA, it does not include individual load forecasts for ESPs. This is because ESP load data is confidential and fluctuates based on customers' commitments. Instead, the CPUC sets an aggregate GHG planning target for all ESPs within each IOU service territory and then requires each ESP to calculate its own confidential GHG Emissions Benchmark using its own load forecast.

In order to account for that uncertainty while forecasting load to set ESP targets, the IRP currently requires ESPs to utilize their most recent year-ahead load forecast submission in the CPUC Resource Adequacy proceeding and extend it out to 2030.[20] Using short-term forecasts from the Resource Adequacy proceeding for long-term planning could lead to setting inaccurate procurement targets in electric sector planning, and increases the risk that a potentially significant portion of Direct Access load will not be planned for in IRP.

This mismatch between short-term forecasts and long-term planning raises several potentially significant issues when integrating ESPs into the IRP process:

- **Uncertainty among ESPs**. As discussed in Section 1.4, 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. In a competitive environment in which customers can always leave and seek service with a different ESP, ESPs will face challenges holding long-term contracts for resources that the IRP process identifies as necessary.

- **Load uncertainty for CCAs and IOUs**. With the expansion of Direct access, load uncertainty for ESPs leads to load uncertainty for CCAs and IOUs. Commercial and industrial customers currently make up about 57 percent of electric load in California. If that load becomes less predictable—more subject to moving between Direct Access and other LSE classes—then all LSEs will have less planning certainty. With less confidence in the load projections that they use in their IRPs, LSEs could be less willing to procure based on

20 ALJ Ruling dated January 24, 2020 describing IRP load forecasts available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M325/K033/325033751.PDF

identified planning needs.

- **ESP load aggregation**. 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 creates a risk that the sum of individually provided ESP forecasts will not add 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. If the Legislature opens more load to Direct Access, this problem will be amplified.

To the extent that Direct Access providers serve a higher share of total load, the CPUC will need a mechanism to ensure that ESPs procure their share of resources that meet GHG emissions reduction targets. These challenges may be manageable, but they require a clear compliance and enforcement regime to align the incentives of ESPs and their customers with IRP objectives. CPUC authority to enforce the IRP planning requirements is limited at this time. Staff recommends that the Legislature consider extending the CPUC's authority to enforce compliance.

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

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.[21] As major capital investments, new renewables projects cannot generally find financing without long-term purchase agreements.

In the past, California has required the IOUs to sign the long-term power purchase agreements needed to finance new generation and guaranteed the IOUs cost-recovery for these purchases. 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 the 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 contracting requirement is necessary to ensure that RPS contracts cover the capital costs needed to finance new renewable projects.

In informal comments to the January 8, 2020 workshop, Direct Access representatives stated that

[21] (R.) 16-02-007, 2019-2020 Proposed Decision on Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning, Figure 2 (p. 36), mailed Feb. 22, 2020,.

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.[22] Furthermore, Shell and Commercial Energy argue that expansion of the DA market will increase market liquidity and encourage LSEs to pursue long-term investments.[23]

Nevertheless, the ESPs have a limited record of entering long-term contacts. The *2019 California Renewable Portfolio Standard Annual Report* found that long-term contracts account for 9 percent of their total portfolio.[24] While the ESPs will not need to reach compliance with the 65 percent long-term contracting requirement until 2024, ESPs will need to make a significant investment in the near term for projects to come online between 2021-2024 to meet the 65 percent target.

CPUC staff is concerned that ESPs' short-term customer commitments may create an impediment to making long-term investments in GHG-reducing resources. Customers seeking lower energy costs will have an incentive to switch to the provider with lower cost portfolio. In a competitive market, this could also impact the CCAs' ability to hold long-term contracts. In their informal comments to the January 8, 2020 workshop, CalCCA stated that uncertainty caused by load migration could undermine the long-term contracts that they have entered into and leave them locked into a fixed price contract as they lose load to lower price competitors. CCAs, who are not guaranteed cost-recovery and risk losing non-residential customers if Direct Access is expanded, may delay investments in renewables and storage to avoid investing on behalf of customers who then depart their service. The risk that load may depart is likely to raise borrowing costs for those projects that CCAs do pursue.

In sum, reopening Direct Access to all non-residential customers, Energy Division staff is concerned that overall levels of renewable generation investment will decline and reduce GHG emission reductions. While the 10-year RPS contracting requirement provides a floor by requiring longer-term investment, reporting and enforcement occur at the end of the compliance period. This means that the CPUC will not be able to rectify the shortfall if LSEs fail to procure the long-term contracts needed to meet their compliance requirements.

2.2 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.

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22 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

23 See Workshop Comments filed by Shell Energy.

24 See *2019 California Renewable Portfolio Standard Annual Report*, pg. 20

The CPUC has very limited jurisdiction over the emission of criteria pollutants and toxic air pollutants.[25] 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 SB 100, 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."[26] Additionally, the CPUC requires that LSEs "minimize localized air pollutants" in their Integrated Resource Plans.

The CPUC's ability to assess the impact of expansion of Direct Access on criterial 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 are the primary source of brown power in the energy resource mix of the system. 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. While the new compliance requirements adopted in RPS and IRP will likely require ESPs to shift toward a greener portfolio, we 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 past practice of relying on unspecified power as a significant source of their procurement, this could lead to an increase in criteria air pollutants.

2.3 Ensuring Reliability with Expansion of Direct Access

2.3.1 How the CPUC Ensures Reliability

The CPUC manages electric reliability through the Resource Adequacy (R. 17-09-020) and IRP proceedings (R.16-02-007). 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 to ensure the resources needed for local grid reliability and renewable integration are under contract.

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[25] 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

[26] Public Utilities Code Section 399.11 (a) (1)

The Resource Adequacy program began implementation in 2006 pursuant to AB 380 (Nunez, 2005). Current Resource Adequacy requirements are meant to provide the energy market with sufficient forward capacity to meet peak demand, ensure local area reliability and ensure reliable integration of renewable energy. LSEs are required to make annual and monthly showing to the CPUC reflecting that they meet their Resource Adequacy system, local and flexible Resource Adequacy requirements. In D. 20-06-002, the CPUC adopted a centralized procurement entity (CPE) that will be charged with procuring local RA on behalf of all LSEs in PG&E's and SCE's service territories.

Longer-run reliability is addressed through the IRP process, which identifies the mix of new and existing resources that will be needed to ensure reliability (as well as meet GHG targets) over the longer run. The IRP identifies long-run needs by modeling system resources ten years into the future to determine the level of procurement needed to meet forecasted demand. If the IRP identifies a shortfall, the CPUC may order new procurement based on those findings, as discussed in Section 2.1.

Investment in new generation benefits all customers by lowering the risks of Resource Adequacy shortfalls for all LSEs. However, because the costs of the investing in new resources are considerable and all LSEs receive the benefits, each LSE has a financial disincentive to invest in new generation. This creates a tendency for an unregulated market to underinvest in reliability, creating the potential for capacity shortages.

Beginning in 2006, California addressed this potential market failure by requiring the IOUs to procure new generation with independent generators on behalf of all LSEs. D.06-07-029 adopted a Cost Allocation Mechanism (CAM) to ensure that IOUs can recover the costs of these investments from other LSEs. The CAM works by allocating the net capacity costs of investments to all customers through a non-bypassable charge. The capacity benefits are then allocated to LSEs based on monthly peak load-shares. The guaranteed cost recovery provided by the CAM mechanism allows the IOUs to act as central procurement agents for the other LSEs in their service territory to ensure that the new resource needs identified through the Commission's long-term planning processes are built and paid for by all customers who will benefit, both bundled and unbundled.

D.20-06-002 adopted a more formal central procurement structure, the Central Procurement Entity (CPE) to ensure that local Resource Adequacy needs are met in PG&E and SCE's service territories. The CPE will procure local Resource Adequacy on behalf of all LSEs and make sure the costs are shared equitably. Initially the IOUs will fulfill the CPE function, but this function may be fulfilled by other entities in the future.

2.3.2 Current Reliability Shortfalls Identified in Resource Adequacy and IRP

Recent trends documented in Energy Division's 2019 *State of the Resource Adequacy Market Report*[27] indicate a tightening market for Resource Adequacy. The Market Report documents that for the 2019 Resource Adequacy compliance year, 11 LSEs had year ahead local deficiencies, 6 had year-ahead system deficiencies, and 5 had year-ahead flexible deficiencies in 2019. One reason reported for local waiver requests was that LSEs could not identify available local capacity at any price. Many

[27]Issued in R.17-09-020 Assigned Commissioner's ruling on September 3, 2019

of these deficiencies persisted through the year in 2019 month-ahead filings. These trends also continued into 2020 Year-ahead filings, where 20 LSE requested local waivers.[28] While the CPE adopted in D. 20-06-002 will procure local Resource Adequacy, system and flex Resource Adequacy requirements will remain the responsibility of the LSEs.

Appendix A includes the list of Resource Adequacy citations issued from 2006-2019. Of the 90 citations issued since 2006, 77 have been issued to ESPs, approximately 85 percent. Compliance with Resource Adequacy obligations is the CPUC's primary mechanism to ensure reliability. The ESPs' poor compliance record is an indication that expanding Direct Access to all non-residential customers could lead to shortfalls in resource adequacy.

Furthermore, the total citation penalties amounts increased sharply in 2018. Prior to 2018 the total annual citations issued averaged $27,518 per year. The CPUC issued $2.6 million in citations in 2018 and $9.5 million in 2019, plus an additional $8.8 million in enforcement penalties. The magnitude of this increase is an indicator of a short supply in Resource Adequacy market. The tightening Resource Adequacy market has made it difficult and more expensive to procure Resource Adequacy contracts, particularly for newer LSEs. LSEs will only pay Resource Adequacy citations if there is no available Resource Adequacy capacity to procure, or the needed Resource Adequacy costs more than the citations themselves. Either way, the LSE's failure to procure Resource Adequacy contracts creates a capacity shortfall for the entire system, which drives up energy prices for all customers and puts system reliability at risk.

The system capacity shortfall identified in the Resource Adequacy proceeding is being addressed in the IRP proceeding. D.19-11-016 ordered that 3,300 MW of additional capacity be procured by Summer 2021 and assigned each LSE a share of the procurement obligation based on their proportion of the total load.[29] D.19-11-016 further required that 50 percent of the required resources come online by August 1, 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 Board that generation contracts for several large Once Through Cooling generators that were slated to retire by December 31, 2020, be extended through 2022.[30]

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. However, D.19-11-016 directed CPUC staff to develop a mechanism similar to CAM 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.[31] This mechanism is still being developed in the IRP proceeding.[32]

28September 2020 Revised State of the Resource Adequacy Market Report.
29 D. 19-11-016, Finding of Fact 5, p.68 and Ordering Paragraph 3, pp. 80-81.
30 D. 19-11-016, Ordering Paragraph 1, pp. 79-80.
31 D. 19-11-016, Ordering Paragraph 5, p. 82.
32 R. 16-02-007

2.3.3 Challenges to Meeting Resource Adequacy Shortfall in a Disaggregated Market

D.19-11-016 is the first time that the CPUC has 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. As stated in D.19-11-016 "[t]his is also an appropriate place to test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP."[33]

There are several challenges to addressing the reliability challenges identified in D.19-11-016. There are now over 40 LSEs that must build new generation. Even if each LSE is each able to meet its resource obligations, it is uncertain whether the state will obtain the most cost-effective mix of energy resources from up to 40 independent procurements that can meet GHG targets while meeting local and flexible resource adequacy.

As explained in Section 2.1.3, load migration makes it challenging for ESPs to accurately forecast load and therefore to sign the long-term contracts needed to finance new resource development. Staff acknowledges that several of the challenges with meeting reliability are not isolated to Direct Access but are also created by load migration from CCA formation. However, as stated in previous sections, reopening Direct Access will exacerbate these challenges since it creates planning and procurement uncertainty for CCAs.

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 the CCAs' 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 about their procurement practices available to the public and claim privilege and confidentiality to avoid disclosing information to the CPUC. This lack of transparency means that the CPUC cannot check on the progress of ESP procurement activities towards compliance targets and propose remedies if it seems likely that an ESP will fail to meet its obligations.

While P.U. Code 394.25 provides the grounds for the CPUC to suspend or revoke an ESP's registration under certain conditions, it does not the CPUC the authority to revoke licenses of ESPs due to repeated failure to comply with procurement requirements. Staff recommends that the Legislature consider extending the authority provided by P.U. Code 394.25 to ensure that a few ESPs who are out of compliance do not undermine the competitive market and put system reliability at risk.

33 D.19-11-016 at 39

2.3.4 Mechanisms Under Development to Address Reliability in a More Fragmented Retail 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, D.19-11-016 allows LSEs to self-procure to meet IRP requirements, 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 also 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. However, it remains to be seen whether a backstop procurement mechanism can deliver generation resources quickly enough to avoid near-term system reliability issues.

The CPUC is also considering new structures to ensure reliability despite the load uncertainty that characterizes the current market in the RA proceeding (R. 17-09-020). 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 entities for Local Resource Adequacy in their respective service territories.

While central procurement has only been adopted for local Resource Adequacy,[34] 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.

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

P.U. Code Sections 366.1 and 366.2 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,[35] 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

[34] D.20-06-002, Ordering Paragraph 3, p. 91.
35 See D.18-10-019 and D.19-10-001.

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.

2.4.1 Failure to meet Procurement Obligations will lead to Cost Shifting

Procurement costs will be equitably allocated to customers if all LSEs meet their own procurement obligations. If LSEs request waivers to meeting their Resource Adequacy requirements, then backstop procurement will be needed, which drives up the overall market cost. In the event the LSE's failure to procure sufficient resources to ensure reliability, the CAISO may procure additional resources under its "Reliability Must Run" program. These CAISO out-of-market procurements are based on a “cost of service” rate that often times is much more expensive than competitive procurements. These costs are allocated to all customers and can lead to cost shifting. To minimize the need to rely on this costly mechanism, the CPUC has developed a backstop procurement mechanism to order procurement through the Resource Adequacy program when one or more LSE fails to meet its procurement obligations. As discussed in the Section 2.3, the CPUC backstop mechanism's costs are allocated to the LSE that is short on its obligation. Reliance on backstop procurement to meet system need will further tighten the market for all LSEs and continue to drive up energy prices, which would also drive up rates for bundled customers. 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.

The cost allocation accounting of new mechanisms such as backstop procurement is extremely complex, and it is not clear how these costs should be reallocated if an LSE goes bankrupt or its customers migrate to a new LSE. Staff is uncertain that these many different mechanisms will continue to function as designed if there are several different types of allocation mechanism layered in the IOU billing systems. If they do not function as designed, there is the potential for additional cost shifting.

2.4.2 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 because 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. Under competitive market conditions we can expect that the customers with a lower cost-of-service will be more likely to choose ESP service since they can reap the greatest benefit in terms of cost savings. This migration 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.

2.4.3 CCAs Have No Mechanism to Recover Stranded Costs

While SB 237 is focused on the potential undue cost shifting between bundled customers and Direct Access customers, there is also the potential cost shifting impacts to CCA customers. With the long-term procurement obligations established in IRP and RPS, a rapid or unforeseeable departure of load departure from CCAs could leave them with significant stranded costs that they cannot fully recover through market transactions. If these stranded costs are significant enough that a CCA fails, residential customers of a CCA, including low-income customers, would be returned to either the IOU or the otherwise designated Provider of Last Resort (POLR).

At this this time, the legislature has not asked the CPUC to consider potential exit fees or negotiated compensation for the CCAs load obligations. However, Staff recommends that the Legislature consider the CPUC's authority in allowing CCAs to recover the costs of investments that are stranded because of unforeseen load departure to address these potential impacts.

3. Recommendations on the Schedule to Reopen Direct Access

The Staff recommendations below identify the key conditions and requirements that ESPs should meet prior to reopening any Direct Access services to nonresidential customers. Staff recommendations also address timing parameters that should be taken into account if the Legislature elects to reopen Direct Access. Should the Legislature enact an expansion of Direct Access to all non-residential customers, staff recommends that the expansion should proceed on a gradual basis to minimize planning disruptions associated with load departure.

<u>Conditions and Demonstrations for Reopening Direct Access:</u>

Determination of reopening Direct Access should be made no earlier than 2024, after the first phase of Direct Access expansion mandated by P.U. Code Section 365.1(f) is completed. This schedule will also allow the IRP procurement ordered by D.19-11-016 to be completed, and the ESPs to demonstrate that they will meet the RPS 10-year contracting requirements. This schedule also allows time for the CPUC to develop, adopt, and implement the procurement mechanisms, such as backstop procurement, that are needed in the event that LSEs fall short of fulfilling any of their procurement obligations.

If the Legislature chooses to open Direct Access, we recommend that reopening be conditioned on ESPs' demonstrated compliance with the following obligations:

- Integrated Resource Planning
  - ESPs submit robust, transparent IRPs that:
    - provide more certainty about individual ESP planning and forecasting over a 10-year time horizon, AND
    - can be meaningfully aggregated with plans from other LSEs to form an integrated resource plan for all CPUC-jurisdictional LSEs without causing reliability or renewable integration issues; AND
  - ESPs either:
    - meet all procurement requirements pursuant to D.19-11-016; OR
    - participate in successful cost allocation of their procurement obligation using the modified CAM and backstop procurement mechanism directed by D.19-11-016: AND
    - demonstrate a track record of procuring new resources in line with their submitted IRP portfolios.

- Renewable Portfolio Standard
  - ESPs meet their RPS obligations for 2021-2024 compliance period; AND
  - ESPs meet 10-year contracting obligations in RPS

- Resource Adequacy (RA)

- ESPs comply with all Resource Adequacy requirements including multi-year year ahead flexible and system, and month ahead system and flexible obligations.

Table 3 (below) provides a timeline for these various compliance obligations.

Table 3: Timeline of compliance obligations for IRP, Resource Adequacy, and RPS.

	2020	2021	2022	2023	2024
Phase One SB 237		4,000 GWh increase to the Direct Access Cap			
IRP Filing Requirements	July 1 LSEs must file long-term procurement and implementation plans		LSEs must file long-term procurement and implementation plans if IRP remains on a two-year cycle		
IRP Procurement (D.19-11-016)	CPUC develops and approves a modified CAM mechanism.	50 % of obligations by Aug, 2021	75 % of obligations by Aug, 2022	100% of obligations by Aug, 2023	
Resource Adequacy Requirements	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.
RPS Compliance	End of the second RPS Compliance Period.				End of the third RPS Compliance Period.

<u>Recommended Direct Access Reopening Schedule:</u>

Should the above conditions and demonstration be met and the Legislature choose to reopen direct access to non-residential customers, the CPUC Energy Division Staff recommends that the Legislature follow historical precedents from SB 695 and SB 237 and phase-in additional Direct Access load incrementally. Incremental phase-in will enable LSEs to better plan for potential load-departures and thus create fewer potential cost-shift and reliability issues. Additionally, a phased-in approach provides consistency and a planning horizon for customers and avoids snap decisions from customers rushing into Direct Access to take advantage of a one-time opportunity. We recommend the following phase-in schedule and conditions:

- Set an initial re-opening schedule of **increments equal to 10 percent of eligible non-residential load per year.**
- Condition each annual expansion on CPUC review and approval of compliance with IRP, Resource Adequacy and RPS requirements, as subject to CPUC approval.
- Order annual expansion to take place on a schedule that will allow Load Serving Entities (LSEs) the ability to fully comply with Resource Adequacy requirements.
- ESPs must comply with the requirements of D.18-06-030 requiring all LSEs (including ESPs) to participate in all aspects of the year-ahead Resource Adequacy process for load they plan to serve in the following year and the "binding load forecast process" adopted in D.19-06-026.

The migration of 10 percent of non-residential load per year will minimize the planning disruptions associated with load departure identified in this report and allow the CPUC and the market sufficient time to develop the structures needed for long-term resource development in a fragmented market.

Recommendations for Legislative Action:

The CPUC recommends that the following legislative action is considered in order to ensure that GHG emissions, reliability and cost shifting provisions are met:

- Provide CPUC clear authority to enforce compliance for IRP GHG goals for all LSEs subject to P.U. Code Section 454.52 (b).
- Ensure that the CPUC continues to have clear authority to enforce the state's Resource Adequacy goals defined in P.U. Code Section 380.
- Amend P.U. Code Section 949.25 to provide the CPUC with the authority to revoke ESP licenses and CCA registration for repeated non-compliance with Resource Adequacy, RPS or IRP requirements.
- Ensure that provisions to ensure that there is no cost shifting as the result of customer moving between different LSE (Electric Corporations, CCAs, and ESPs) are applied equitable to all customers.

Consumer Protection Enforcement Division Resource Adequacy Citations

Compliance Year	Citations Issued	Citations Issued on ESPs	LSEs Cited	Total Citation Penalties	Enforcement Cases	Enforcement Cases on ESPs	LSEs Enforced	Total Enforcement Penalties
2006	1	1	Commerce Energy	$1,500	0	0		0
2007	3	3	3Phases; Commerce Energy; Amer. Util. Network	$5,000	1	1	CNE	$107,500
2008	7	7	3Phases (2); Commerce Energy (2); Corona DWP; Sempra Energy; Shell Energy	$17,000	1	1	Calpine	$225,000
2009	4	4	Commerce Energy (3); CNE	$26,500	1	1	CNE	$300,000
2010	5	4	Commerce Energy; Pilot Power Group (2), Direct Energy Business, SDG&E	$25,500	0	0		0
2011	2	2	Liberty Power; Tiger Nat Gas	$7,000	1	0	PG&E	$215,000
2012	4	3	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0	0		0
2013	5	4	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0	0		0
2014	1	1	3 Phases	$5,000	0	0		0
2015	6	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000	0	0		0
2016	3	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500	0	0		0
2017	6	4	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110	0	0		0
2018	10	8	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,593,439	0	0		0
2019	33	27	Just Energy Solutions (12), Commercial Energy (8), Agera Energy (6), San Jose Clean Energy (3), East Bay Community Energy (2), Valley Clean Energy (2), Pioneer Community Energy	$9,549,716	21	18		$2,758,560
Total	90	77		$12,473,365	25	21		$3,606,061

(END OF ATTACHMENT A)