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Subject: City and County of San Francisco Comments on Draft White Paper

Summary

The City and County of San Francisco (San Francisco) submits these comments on the Commission staff's recently issued paper -- California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (Draft White Paper).

San Francisco, through its Public Utilities Commission (SFPUC), operates San Francisco's Community Choice Aggregation (CCA) program, CleanPowerSF. CleanPowerSF provides low-GHG electric energy to about 80,000 San Francisco residents and businesses, and plans to enroll all remaining eligible accounts by July 2019 for a total 360,000 accounts. The SFPUC also represents the interests of all city residents and businesses, regardless of their service provider, before regulatory agencies such as the Commission.

In addition, the SFPUC operates San Francisco's municipal water, waste water, and power utilities. Like other electric publicly owned utilities (POUs), who serve 25% of California load,[1] the SFPUC supports the goals of reliability, decarbonization, and affordability articulated in the Draft White Paper. Although not regulated by the Commission, POUs meet and exceed the requirements of state law that address reliability and decarbonization. POUs also have a long history of providing affordable service to their communities, generally at rates well below those

[1] http://www.energy.ca.gov/pou_reporting/

of investor-owned utilities.[2] CCAs, as government agencies overseen by community members and elected boards, similar to POUs, are equally committed to achieving and exceeding goals articulated in the Draft White Paper.

CleanPowerSF is also a member of the California Community Choice Association (CalCCA) and supports their comments. San Francisco particularly notes CalCCA's comments that comparisons between the current market structure and the market structure that led to the California energy crisis are incorrect and unfounded.

While the Draft White Paper looks outside California for potential market structures and concludes that no single structure evaluated meets California's needs, the Draft White Paper does not look "inward" to the various on-going proceedings at the CPUC. San Francisco appreciates the Customer Choice team's follow-up to the Draft White Paper asking stakeholders to "assess whether issues raised in the Draft Green Book are being examined in current proceedings and perform a gap analysis to identify the issues that remain unaddressed."[3]

As shown below, such an "inward looking" review will confirm that:

- The Commission already has sufficient authority to meet the goals articulated in the Draft White Paper;
- The Commission's recent decision in the Integrated Resource Planning (IRP) proceeding (D.18-02-018) has already examined the effects of many of the issues raised in the Draft White Paper; and
- Almost all of the issues identified in the Draft White Paper are currently, or soon could be, under consideration in on-going Commission proceedings.

Many of these proceedings not only provide useful information on the scope of issues identified in the Draft White Paper but also identify proposed solutions. A review of these proceedings also confirm that CCAs, such as CleanPowerSF, are well-positioned, and can play a major role in achieving the Draft White Paper's goals of reliability, decarbonization, and affordability.

Indeed, as CalCCA and others have commented, the Draft White Paper appears to be a solution in search of a problem.

San Francisco does not believe that any additional docket or proceeding needs to be established in order to achieve the goals articulated in the Draft White Paper, and believes that

[2] https://www.publicpower.org/periodical/article/coast-coast-public-power-costs-less
[3] Request for Informal Comments and Recommended Solutions of the Draft Green Book (May 21, 2018, p. 1).

doing so would be duplicative and create additional work for both Commission staff and stakeholders. If necessary, the Commission could use a revised Draft White Paper to identify a path forward, recognizing the relevant proceedings where identified issues would be addressed. Such an effort could be similar to the Energy Action Plan developed by the Commission in conjunction with the California Energy Commission (CEC) and California ISO (CAISO).

San Francisco's comments on the Draft White Paper address the following points:

- The role of the Commission's IRP process in coordinating the activities of California's various energy players;
- The Commission's vision of California's energy future as identified in the Commission's recent IRP decision; and
- Achievement of the goals articulaed in the Draft White Paper:
    - Reliability
    - Decarbonization; and
    - Affordability

Also, significantly not addressed in the Draft White Paper, is how California should transition from one market structure to another.

I. <u>**The Commission's recently completed IRP process already provides a framework for coordinating the activities of California's various energy players.**</u>

The Draft White Paper only mentions once, in passing,[4] the Commission's IRP process (R.16-02-007) despite the significant effect the IRP process will have on improving coordination amongst California's load-serving entities and providing early warning of potential problems.

As President Picker noted in his introduction to the Draft White Paper, "the paper asks us to consider such questions as:

- How do we protect safe delivery of electricity to meet customer demand in an increasingly fragmented market?
- How will we ensure that increasing fragmentation of suppliers and buyers will add up to meet our ambitious clean energy goals?
- How will we make sure that different players are meeting their responsibilities to provide all the energy resources we need to make the grid work?"[5]

All of these issues are being evaluated and can be considered in the Commission's IRP process. As the Commission recently concluded in D.18-02-018:

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[4] Draft White Paper, p. 17.

[5] *Id*. at p. iii.

> The Commission's authority [in the IRP process] is primarily with respect to the planning process, in order to assess the aggregated impact of all of the LSE plans combined, to ensure that the portion of the electric sector under our authority and jurisdiction is meeting its GHG and reliability obligations on behalf of the electric system. As we note below, with some exceptions related to renewable integration resources, the procurement decisions, customer rates, and contract terms and conditions (outside of the RPS) are the domain of the CCA governing boards and not the Commission.
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> . . . We also agree with [Peninsula Clean Energy's] PCE's comments that state that the overall IRP process is designed to achieve its intended GHG targets and "ensure a safe, reliable and cost-effective electricity supply in California" while respecting the role of individual CCA governing boards to direct an individual CCA's procurement. These comments appropriately balance the role of the Commission in effectuating state policy -- state policy that sets statewide goals that all LSEs have a shared obligation to meet, including CCAs -- along with the obligations of the CCAs in achieving it at the local level.[6]

At a minimum, the IRP process, combined with the Commission's resource adequacy (RA) and renewable portfolio standard (RPS) processes, should provide California decision-makers with an overall view of how California is achieving its energy goals and, equally important, provide advance notice of potential problems. Subject to Commission jurisdiction, the IRP, RA and RPS processes could also identify proposed solutions if future concerns are identified.

II. The Commission's IRP process provides a vision of California's energy future.

The extensive planning process recently undertaken by the Commission in the IRP proceeding, and its adoption by the Commission in D.18-02-018,[7] identifies a path for California's energy future and the role of non-IOU providers such as CCAs.

For example, although numerous parties, including CalCCA, had concerns about the inputs and assumptions used in the IRP process,[8] the IRP's final conclusions should be noted. If California's individual LSEs achieve the IRP goals adopted by the Commission, California will have:

- Reliable service with a 131% reserve margin, well above the 115% needed for reliability;[9]

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[6] D.18-02-018, p. 26 (emphasis added).
[7] *Id*. at p. 172, Ordering Paragraph 9.
[8] See, for example, Reply Comments of CalCCA on the Proposed Reference System Plan in R.16-02-007, which identifies some of the issues and concerns raised by parties regarding the RESOLVE model used in the IRP planning process (November 9, 2017, pgs. 7-13).
[9] Proposed Reference System Plan, September 19, 2017, p. 68.

- A green energy portfolio comparable to achieving a 58% RPS requirement by 2030;[10] and
- Reasonable rates that are only 1% above what rates would otherwise have been.[11]

These goals would be achieved despite the closure of Diablo Canyon nuclear power plant during 2024-2025[12] and two concerns identified as potential problems in the Draft White Paper:[13]

- An ever-increasing amount of intermittent renewable resources;[14] and
- The retirement of all of California's once-through-cooling (OTC) natural gas fleet.[15]

To achieve these goals, there are four major drivers identified in the IRP:

- California's successful energy efficiency and behind-the-meter generation programs need to continue.[16] These efforts will be enhanced by the development of CCAs.
- LSEs must meet, and slightly exceed (58%) their mandatory RPS target of 50% by 2030. This is consistent with the goal of almost all CCAs to exceed the current RPS standards.
- All remaining existing resources continue in operation and are re-contracted for when existing contracts expire.[17] As CCAs grow and must meet their RA and energy needs, CCAs will have a strong incentive to contract for these resources.
- Revenue sufficiency must be provided to that portion of California's existing natural gas fleet necessary for backstop and renewable integration services needed to maintain reliable service.[18]

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[10] "An RPS of ~58% is a byproduct of achieving the 42 MMT carbon goal" established in the IRP (Proposed Reference System Plan, p. 58).

[11] The "total incremental cost is $239 million/year, equivalent to approximately a 1% increase in system average rates by 2030." (Proposed Reference System Plan, p. 9).

[12] Proposed Reference System Plan, p 27.

[13] "Today, significant structural changes are challenging the program's ability to meet adequate reserve margins under the current market and program design. These changes include increasing intermittent renewable resources, the upcoming retirement of natural gas power plants due to once through cooling requirements and lack of revenue, and the rapid expansion of CCAs resulting in customer migration." (Draft White Paper, p. 16.)

[14] The Proposed Reference System Plan would add an additional 10,000 MW of intermittent renewable resources to California's electric grid on top of existing intermittent resources. (Proposed Reference System Plan, p. 68.)

[15] Proposed Reference System Plan, pgs. 27, 34.

[16] The Proposed Reference System Plan assumes "Projected achievement of demand-side programs under current policy (e.g. forecast of EE achievement, BTM PV adoption under NEM tariff)." (Proposed Reference System Plan, p. 26.) Behind-the-Meter generation would reach 16 GW by 2030 (p. 30) and energy efficiency would only be 1.5X mid-level additional achievable energy efficiency, which is below the 2X target set by SB 350.

[17] These are "baseline resources" or existing resources less planned retirements (Proposed Reference System Plan, p. 27).

Other than addressing the issue of revenue sufficiency for natural gas plants (identified in the Draft White Paper[19] and discussed further below) the other three drivers are unaffected, and perhaps even enhanced by, changes to California's energy structure.

III. <u>California can and will maintain reliable electric service even with the expansion of CCAs.</u>

The Draft White Paper posits the question of: "Who will execute the long-term contracts that can be used to finance construction of new facilities going forward?"[20] As discussed in this section, and the following section on decarbonization, the need for IOU procurement for new non-RPS power plants should be minimal and procurement needed to meet RPS requirements will continue to add capacity to the system.

a. <u>The Commission already has the ability to ensure reliable electric service for customers.</u>

As the Draft White Paper notes,[21] the Commission already has the authority under Public Utilities Code Section 380 to set and enforce resource adequacy standards on load-serving entities (LSEs) be they investor-owned utilities (IOUs), energy service providers (ESPs), or Community Choice Aggregators (CCAs).[22] These requirements are currently set on an annual basis.

A perceived concern of the Draft White Paper is that this yearly requirement may not be sufficient to ensure long-term reliability concerns.[23] The CPUC already has the following mechanisms to address this concern;

- As the Draft White Paper itself notes,[24] the Commission is considering adopting a multi-year RA requirement in its RA proceeding (R.17-09-020);
- Per SB 350, by 2021, 2/3 of each LSE's RPS requirement must be met from resources under long-term (10 years or more) ownership/contractual arrangements;
- Through the PCIA rulemaking, the Commission can ensure that existing long-term utility-owned/contracted resources will continue to serve California customers by making these assets and their generation and associated attributes available to the entities that serve those customers' loads;

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[18] Proposed Reference System Plan, pgs. 59-60.
[19] Draft White Paper, p. 16.
[20] *Id*. at p. 6.
[21] *Id*. at p. 16.
[22] For purposes of these comments, the term "LSEs" generally refers to IOUs, ESPs, and CCAs.
[23] *Id*.
[24] *Id*.

- The Commission retains Cost Allocation Methodology (CAM) authority to procure resources needed for reliability, although as discussed below the need for such resources is likely to be minimal; and
- Additional revenue streams (such as changes to the flexible RA requirement or development of a renewable integration charge) could provide an additional revenue stream for maintaining necessary gas-fired generation.

LSEs, including CCAs, will be subject to whatever outcome occurs in the RA proceeding. In addition, the CPUC already has in place penalty provisions for CPUC-jurisdictional LSEs that fail to meet their RA obligations.

b. <u>The IOU's role in new resource procurement is likely to be minimized – responsibility should follow the load.</u>

The Draft White Paper posits that the IOUs "are often pressured to procure resources that no other provider wants to buy."[25] One of the primary reasons for CAM, where the incumbent utility builds a power plant but then assigns the costs to customers (IOU, CCA, DA) has been to build new gas-fired power plants needed for reliability. Given the cost of a new gas-fired plant (estimated at $150 to $180/kW[26]) it was not expected that market revenues (such as energy and RA capacity sales) would be sufficient to recover costs.

However, the analysis conducted in the IRP proceeding concluded that there is no need to build any new gas-fired power plants over the planning horizon studies as they are neither needed for reliability nor cost-effective.[27] This appears contrary to the Draft White Paper's concern that new gas-fired generation needs to be built. [28] If, as the IRP appears to conclude, there is not a need for new gas-fired power plants, then the need for IOU procurement through a mechanism such as CAM is significantly reduced.

As the IRP model is designed to look at system-wide optimization, it is possible that there might still be a need for new generation to address a local reliability concern. However, as the Draft

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[25] *Id*. at p. 19.
[26] California Energy Commission, FINAL STAFF REPORT - ESTIMATED COST OF NEW RENEWABLE AND FOSSIL GENERATION IN CALIFORNIA (March 2015, CEC-200-2014-003-SF, p. 8).
[27] The " RESOLVE [model] does not select new gas [fired power plants] in any of the cases studied." (Proposed Reference System Plan, p. 60.)
[28] The Draft White Paper (p. 22) appears to believe that "Flexible, fast-ramping natural gas units can bridge this reliability gap during the technology transition, . . ." while the IRP appears to conclude maintenance of the existing gas fleet is sufficient. (Proposed Reference System Plan, p. 60). Additionally, extensive investment in new gas-fired plants would create a next generation of gas-fired plants (with expected 20 or 30 year life cycles) making it harder to achieve California's GHG reduction goals and potentially delaying the deployment of storage alternatives.

White Paper notes,[29] and has already been shown in Southern California, alternatives to new gas-fired generation such as transmission upgrades, voltage support installation, storage, and demand response appear to be able to address many of these concerns. These costs could continue to be recovered through transmission and distribution rates.

c. The major reliability need identified by the IRP process is to maintain some portion of the existing gas fleet.

One of the main conclusions of the IRP modeling, and noted in the Draft White Paper, is that some portion of California's natural gas fleet remaining after the retirement of those plants subject to OTC constraints will be needed, at least in the near to mid-term, to meet reliability needs and provide renewable integration services.[30] Both the Draft White Paper and the IRP note that some revenue source will be needed for these plants, as the existing revenue streams (RA capacity and energy sales) may not be sufficient to ensure cost recovery.[31] Revenues from energy sales specifically are expected to be reduced as these plants will run-less and receive lower energy prices due to the presence of large amounts of renewable energy.

The cost of maintaining these gas-fired power plants should be significantly cheaper than the cost of CAM. The CAISO's payments to keep generators on-line, through its Capacity Procurement Mechanism (CPM) is $75/kW year.[32] The Proposed Decision in the RA Proceeding has already proposed a solution to keeping gas plants in operation by proposing that CPUC-regulated entities engage in necessary procurement of these plants rather than relying on ISO backstop procurement.

Other options that move beyond the paradigm of the incumbent utility being the sole provider of such resources could include modifications to the flexible RA payment process, creation of separate renewable integration charge,[33] as well as the concept of a "central provider" (which may or may not be the incumbent utility). Under these other options, CCAs would be responsible for their share of costs to ensure a reliable electric grid and should be allowed to self-procure their share of any requirement.

d. Making the incumbent utilities' resources available to those that serve load.

[29] "Since 2013, the CPUC has looked at storage as a viable alternative to generation in constrained areas." (Draft White Paper, p. 13.)
[30] Proposed Reference System Plan, p. 60. It appears that in the longer-term storage, if costs drop significantly, could replace these plants.
[31] Draft White Paper, p. 16 and Proposed Reference System Plan, pgs. 59-60.
[32] This is a "soft cap" thus depending upon market conditions prices could be less. Prices above the soft cap must be justified. See, CPUC Energy Division 2016 Resource Adequacy Report (June 2017, p. 32).
[33] SB 350 already provides the CPUC with the ability to establish such a charge, including the opportunity to make long-term investments if needed. Equally important, SB 350 allows CCAs (but not ESPs) the opportunity to self-procure their own share of any renewable integration needs.

The IRP's conclusion that reliable service will be achieved through its planning horizon assumes that all existing resources (other than OTC units) remain on-line, presumably even if the underlying contracts expire. A significant portion of these resources are currently under control of the incumbent utilities. In addition to ownership of some gas-fired plants, the incumbent utilities still retain other resources through ownership, primarily hydroelectric resources and until 2024-2025 PG&E's Diablo Canyon resources. The incumbent utilities also hold significant amounts of long-term contracts for RPS-eligible resources.

The Commission is currently examining the treatment of the costs, energy, and environmental attributes of these resources in the PCIA OIR (R. 17-06-026). Through this proceeding, the Commission can ensure that these resources will remain available to serve California load for the life of the resources. For example, CalCCA has proposed an auction mechanism (the Staggered Portfolio Auction) to make these resources available to other LSEs such as CCAs that are now increasingly serving California's LSEs.

e. <u>On-going increases in resource adequacy capacity as a result of the RPS requirement.</u>

Whereas in the past resources were added to the electric system to meet reliability needs, now resources are being added to the system in order to meet RPS requirements. Even though these resources have a lower RA value than traditional fossil-fueled resources, they still contribute additional RA capacity to the system. As previously noted, implementation of the resource plan specified in the IRP proceeding would result in an electric system with a 131% reserve margin. Almost all of this increase at the utility level is driven not by reliability needs but by the need to bring new RPS resources on-line to meet RPS requirements and California's GHG reduction targets. In addition, by 2021, 2/3 of all RPS energy needs must be met through long-term ownership or contract per SB 350. This should further provide the long-term certainty that generators are seeking as they consider new projects.

IV. <u>CCAs are in the forefront of decarbonizing California's electric grid.</u>

a. <u>CCA are making significant investments in RPS-eligible resources.</u>

In the IRP proceeding, the Commission identified an optimal resource portfolio that was equivalent to a 58% RPS requirement. The Draft White Paper appears concerned that CCAs will not be able to make the necessary investments to meet their own, and California's, RPS requirements.

However, as the Draft White Paper itself notes, while California's IOUs are at 35% RPS-eligible energy, most CCAs are significantly above that level[34] even though many of them have only recently begun operation. Almost all CCAs have adopted goals to exceed applicable RPS

[34] Draft White Paper, p. 11.

requirements. As CalCCA notes in its comments, CCAs are making over 1,100 MW of new investment in RPS-eligible resources, the majority of which is under long-term contract. Indeed, given that the incumbent utilities have already met their RPS requirements, it is mainly CCAs that are now acquiring new resources. San Francisco recently signed two long term contracts for a total of 147 MW of California, to-be-constructed, solar and wind energy.

b. The CPUC already has the ability to ensure compliance with California's RPS requirements.

As the Draft White Paper notes, "[t]he state's RPS requirements apply to all LSEs. The CPUC administers the RPS program for IOUs, CCAs and ESPs."[35] The Commission also has statutory authority to require the procurement of renewable resources in excess of the minimum RPS standard.[36] Thus, the Commission could set a higher RPS requirement even in advance of the possible adoption of SB 100 that would apply to all LSEs.

c. CCAs must meet the same long-term contract requirements as the incumbent utilities.

As noted previously, under SB 350, CCAs are required to meet 2/3 of their RPS requirements from ownership or long-term contracts by 2021. This provides a significant incentive for CCAs to procure new resources and limits their ability to procure from existing sources, most of which are already under long-term contract.

d. The RPS penalty structure already provides a strong incentive for LSEs to meet their RPS requirements.

In Decision 18-05-026, the Commission reconfirmed its penalty structure for RPS compliance that applies to LSEs.[37] The readopted penalty structure sets penalty levels at $50/REC and a maximum penalty for non-compliance at $25 million/year. This provides a strong incentive for LSEs to meet their RPS requirements as the$50/REC value is likely significantly above the cost of procuring RPS resources.

The maximum penalty for non-compliance of $25 million/year results in a significantly more punitive penalty structure for smaller LSEs, such as the smaller CCAs, that the CPUC appears to be most concerned about meeting their RPS requirements. This constitutes a significant portion of a smaller LSEs total revenues, but is a drop in the bucket for non-compliance by a large incumbent utility.[38] If the Commission is concerned about achieving its RPS compliance goals it may want to consider equalizing this penalty structure.

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[35] *Id*. at p. 10.
[36] Public Utilities Code 399.15(b)(3).
[37] D.18-05-026.
[38] At $50/MWh the penalty level is capped at 500,000 MWh of non-compliance. This would equal 100% of a small to mid-size CCA (1,500,000 MWh sales X 33% RPS compliance) but only 2.5% of a large IOU's

V. CCAs already provide service at bills comparable to those charged by the IOUs.

a. The IRP assumes a modest rate increase while ensuring reliability and decarbonization.

As noted above, the IRP assumes a 1% rate increase above its baseline forecast by 2030 even while achieving a 58% RPS-equivalent resource portfolio and a reliable electric system with a higher than required reserve margin (131% vs. 115%). Embedded in this rate assumption is cost recovery for all existing resources (including gas-fired generation) as well as necessary investments in the incumbent utilities' transmission and distribution systems.[39]

In addition, as CalCCA's comments amply demonstrate, in terms of affordability, there is little or no evidence that IOU procurement is less expensive than CCA procurement, CCAs can achieve investment-grade credit ratings similar to the IOUs, recent CCA contracts do not show a significant "non-IOU" cost premium, and CCAs can take advantage of tax-exempt financing and do not pay dividends to shareholders. San Francisco strongly supports the comments of CalCCA on the issue of affordability.

Conclusion

San Francisco appreciates the opportunity to provide comments on the Draft White Paper and looks forward to participation in the Commission's June 22, 2018 en banc.

Respectfully submitted,

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RPS obligation (60,000,000 MWh sales X 33% RPS compliance equals 20,000,000 MWh, 500,000 MWh of which is 2.5%).

[39] "Costs other than IRP [are] projected to increase revenue requirements by 11% (real) over 2018-2030, driven largely by distribution and transmission costs." (Proposed Reference System Plan, p. 65.)