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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes	Rulemaking 20-05-003 (Filed May 7, 2020)

THE PROTECT OUR COMMUNITIES FOUNDATION COMMENTS IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ADDITIONAL PROPOSAL FOR A RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM

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Pursuant to the Email Ruling Partially Granting Joint Inventor-Owned Utilities' Request For An Extension Of Time For Comments In Response To Administrative Law Judge's Ruling Seeking Comments On Additional Proposal For A Reliable And Clean Power Procurement Program (Ruling),[1] PCF timely files these comments.

[1] R.20-05-003, Email Ruling Partially Granting Joint Inventor-Owned Utilities' Request For An Extension Of Time For Comments In Response To Administrative Law Judge's Ruling Seeking Comments On Additional Proposal For A Reliable And Clean Power Procurement Program (July 13, 2026), p. 10.

I. INTRODUCTION

Linking long-term system planning to enforceable procurement obligations is essential if California is to build the electricity infrastructure its climate and reliability goals require. Yet the Reliable and Clean Power Procurement Program (RCPPP) framework as proposed overbuilds expensive front-of-meter resources and underutilizes the cleanest and most affordable electricity resource available to California ratepayers: behind-the-meter solar plus storage (BTM SPS). Aggregated BTM SPS and virtual power plants (VPPs) have been proven to provide dispatchable capacity, but both remain excluded from Commission modeling and procurement orders.

BTM SPS represents a unique class of electricity resources: it is installed primarily at customer expense, requires no new transmission infrastructure, faces no interconnection queue delays, and can be deployed far faster than utility-scale projects. When aggregated into VPPs, BTM SPS provides dispatchable reliability services that can be quantified and verified. California ratepayers who install rooftop solar are directly reducing their energy costs and reducing the system's need for expensive peaking resources. By aggregating these investments and developing VPPs, LSEs can provide further benefits to the grid.

Yet the Commission's current regulatory framework does not acknowledge these investments in its procurement planning processes and analyses. RESOLVE, the Commission's capacity expansion model that underpins the Preferred System Plan (PSP) portfolio and the RCPPP proposal,[2] currently treats BTM SPS as a demand modifier instead of optimizable supply. The RESOLVE model penalizes LSEs for customer-sited investments that benefit the system, and rewards LSEs only for utility-scale contracts which require expensive transmission and result in higher ratepayer costs.

[2] ALJ Ruling, p. 8.

The Commission also does not count BTM SPS resources toward LSE resource adequacy (RA) net qualifying capacity (NQC). LSEs cannot receive credit for encouraging customer-sited generation, therefore they have no programmatic reason to invest in VPPs or BTM SPS deployment—even when those resources would serve ratepayers more cheaply, quickly, and effectively than utility-scale alternatives.

The Commission remains statutorily obligated to ensure that BTM solar continues to grow sustainably,[3] and yet the IEPR forecast predicts substantially slower levels of near-term BTM SPS growth due to the elimination of the Investment Tax Credit.[4] The RCPPP framework proposed in this Ruling provides an important opportunity to reinvest in BTM SPS. PCF urges the Commission to adopt the framework with three modifications: (1) direct the Energy Division to model BTM SPS and VPPs as optimizable supply resources in RESOLVE; (2) create a BTM SPS and VPP resource category in RCPPP procurement requirements; and (3) implement an NQC value for BTM SPS and VPPs. Ensuring that BTM SPS is awarded an NQC value, counted toward procurement requirements, and integrated into the Commission's resource modeling, would reduce ratepayer costs, accelerate clean energy deployment, and improve grid reliability.

The RCPPP framework proposed in this Ruling presents an opportunity to comply with the Commission's statutory mandates pursuant to section 454.57(e)(4)(B) in its IRP process.[5] By including BTM SPS and VPP resources as an eligible procurement category, the Commission can create a financial incentive for LSEs to invest in resources that will reduce ratepayer bills and carbon emissions and improve grid reliability simultaneously. BTM SPS and VPPs can be

[3] Pub. Util. Code § 2827.1, subd. (b)(1).
[4] CEC, Final 2025 Integrated Energy Policy Report (July 15, 2026), p. 60.
[5] Section 454.57(e)(4)(B) requires the Commission to consider "cost-effective and feasible alternative to transmission capacity expansions, including the use of energy storage resource, renewable energy resources, or zero-carbon resources" as part of the IRP process.

deployed quickly and incrementally, delivering greenhouse gas emission reductions and additional resources to replace expensive market-supplied fossil power sooner than large renewable projects that take years to plan, build and interconnect. Ratepayers should not be compelled to continue to subsidize expensive, unnecessary and often unreliable utility scale resources.

II. RESPONSES TO QUESTIONS POSED IN RULING

1. Does this ruling describe a workable framework for an RCPPP that will achieve the goals of IRP, pursuant to SB 350? Why or why not?

The Commission should implement several improvements to help achieve the goals of the IRP, pursuant to SB 350. As written, the proposal fails to meet SB 350's requirements to procure zero-carbon-emitting resources to the maximum extent reasonable, [6] reduce greenhouse gas emissions, minimize impacts on ratepayer bills, and enable each electrical corporation to serve its customers at just and reasonable rates.[7]

The proposed framework fails to meet SB 350's statutory mandate that the IRP portfolio rely on zero-carbon resources to the maximum extent reasonable. Nowhere does the Ruling identify BTM SPS or aggregated VPP capacity as a distinct, eligible resource category for LSEs to meet RCPPP procurement requirements. The Ruling discusses applying net qualifying capacity (NQC) to determine the new resource need.[8] However, BTM SPS and VPPs are ineligible for an NQC value in the Commission's models. Further, the Ruling's language and proposed requirements misguidedly contemplate only utility scale resources through its presumption of minimum ten-year offtake agreements.[9]

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[6] Pub. Util. Code § 454.51.
[7] Pub. Util. Code § 454.52.
[8] R.20-05-003, Administrative Law Judge's Ruling Seeking Comments On Additional Proposal For A Reliable And Clean Power Procurement Program (June 23, 2026) (ALJ Ruling), p. 8.
[9] ALJ Ruling, p. 11.

The RCPPP proposal effectively subsidizes utility scale resources by failing to account for the avoided transmission cost benefits and other locational benefits of BTM SPS and VPPs. A recent study released by the University of California Energy Institute shows that due to "leakage" created by using generation resources outside of California, which require transport over long distances with expensive transmission lines, California has achieved only half of the greenhouse gas emission reductions that are credited to utilities.[10] Resources such as BTM SPS and VPPs can prevent the need for the construction of expensive new transmission lines by supplying power at load centers and capture 100% of the greenhouse gas emission reductions, as envisioned by SB 350. And, revising the proposal to implement a QC value for BTM SPS and VPPs would create additional affordability benefits beyond the fact that BTM SPS and VPPs are cheap and easily implementable resources.[11]

Given section 454.51(a)'s direction to the Commission to ensure a diverse and balanced portfolio relying on zero-carbon-emitting resources to the maximum extent reasonable,[12] the Commission should revise the proposal to define and include a BTM SPS/VPP category so that BTM SPS can compete for, and can satisfy, RCPPP obligations on an equal footing with utility-scale resources. BTM SPS should not merely serve as an option LSEs may pursue informally through their own demand-side programs, as the Ruling's brief reference to demand-side management suggests.[13]

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[10] James Bushnell and Kevin Novan, "Electricity Sector Emissions Leakage in California's Cap-and-Trade Program," Energy Institute Working Papers, WP365, https://escholarship.org/uc/item/9zk9p6t8, 2026.

[11] Acadia Center, Grid Action Report: July 4th Heat Wave How Clean Energy Provides Cost Savings and Boosts Grid Reliability During Extreme Heat (July 9, 2026), available at https://acadiacenter.org/resource/grid-action-report-july-4th-heat-wave/.

[12] Pub. Util. Code § 454.51, subd. (a).

[13] ALJ Ruling, p. 11 ("Likewise, LSEs would be incentivized to affect their load shape and/or their load in general through investment in demand-side management (for example, energy efficiency or demand response) to help reduce their resource needs in the future.").

No framework can achieve reliable and clean power procurement, as the IRP goals require, if RESOLVE does not accurately determine and include all available supply resources. SB 350 requires the Commission's IRP process to identify the least-cost, best-fit resources for California's electricity needs. Any model, like the Commission's current RESOLVE model, that treats BTM solar as a fixed demand adjustment, rather than as a candidate supply resource to be optimized, cannot identify the least-cost portfolio or comply with SB 350.

Customer-sited SPS resources offer attributes that utility-scale alternatives do not, such as no transmission costs and interconnection queue delays, full GHG reduction benefits, ecosystem preservation benefits, faster deployment, diversification of portfolios away from CAISO market price volatility, and installation financed primarily by customers rather than ratepayers.[14] When deployed through virtual power plant (VPP) programs, BTM resources can also provide firm, dispatchable capacity with measurable reliability value.[15] Discounting these resources will produce procurement requirements that are more expensive and less clean than necessary.

To ensure a workable RCPPP framework, consistent with SB 350's least-cost mandate and greenhouse gas reduction goals, the Commission should model BTM SPS and VPPs as optimizable supply in RESOLVE and include BTM SPS capacity as an eligible resource category in RCPPP procurement requirements.

2. Will the proposal described in this ruling be simpler to implement than other proposals under consideration? Why or why not? Compare and contrast benefits and costs as directly as possible.

The proposal will add additional complexity and impose additional, unnecessary costs. There will be two different accreditation regimes for IRP and RA—marginal ELCC for RCPPP

[14] *See, e.g.* U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update (January 2025), p. 10-14 (listing some of the benefits of VPPs).
[15] *See* U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update (January 2025), p. 10 ("10-20% of 2030 peak demand could be served by VPPs.").

and Slice of Day rules for RA. [16] The RCPPP itself will add an additional layer of process on top of existing requirements such as RA, RPS, and long lead time (LLT) procurement. The additional complexity will increase costs for LSEs, which must keep track of a multitude of new procurement requirements. Few, if any, benefits will accrue from having two different accreditation regimes and tracking requirements. However, if the RCPPP proposal includes BTM SPS and VPPs as part of its TPP and PSP portfolios both environmental and economic benefits will accrue, as detailed in PCF's answer to Question 1, above.

3. **Is this ruling's proposal preferable to the current ad hoc procurement order process? Why or why not? Compare and contrast benefits and costs as directly as possible.**

A programmatic framework could be preferable because the predictable nature of the procurement orders would allow for better planning and potentially lower costs. Like the Commission's current ad hoc procurement orders, the RCPPP proposal requires expensive procurement with long lead times based on uncertain forecasts before lower-cost alternatives are implemented. An RCPPP in which the Commission identifies a provisional need and then evaluates first whether local resources like BTM SPS and VPP can meet that need, would ensure predictability without prioritizing, or indeed embedding, utility-scale resources. BTM SPS aggregators and VPP providers currently rely on unpredictable state funding[17] or incentive programs[18] to maintain viability.

[16] ALJ Ruling, p. 3.
[17] California Demand Side Grid Support, Frequently Asked Questions (last accessed August 14, 2026), available at https://dsgs.olivineinc.com/faq/.
[18] CPUC, Emergency Load Reduction Program (last accessed August 14, 2026), available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program (listing as eligible "Aggregators of Virtual Power Plants, i.e. a company that can aggregate and control resources such as batteries across multiple customer locations.").

4. Are there other proposals already under consideration that better make the connection between long-term resource and transmission planning and LSE resource procurement? If so, which ones, and why? Compare and contrast benefits and costs as directly as possible.

Because the RESOLVE model fails to consider, much less prioritize BTM SPS, and the Commission's prior decisions do not account for the benefits or BTM SPS and VPPs as valid resources, the Commission should not move forward with the proposal set forth in the Ruling. Selecting among the competing proposals in this proceeding would result in fragmenting the RCPPP proposal across two IRP dockets. Given the rapidly evolving estimates of future energy demand in California[19], the implementation of AB 825,[20] and the upcoming election which will result in a new governor, the Commission should develop the evidentiary record in its new IRP proceeding, R.25-06-019, before implementing the proposed RCPPP.

The Commission should establish a dedicated, minimum BTM SPS/VPP procurement requirement, comparable to the resource-specific requirements that the Commission adopted in prior mid-term reliability procurement orders.[21] Adopting an NQC value for BTM SPS and VPPs and determining a dedicated minimum requirement are necessary predicates to adopting a RCPPP framework because no incentive currently exists for LSEs to procure BTM SPS. Absent an incentive to procure aggregated BTM SPS and VPPs, utilities will continue procuring utility-scale resources almost exclusively — despite the reliability benefits that BTM SPS and VPPs resources provide.[22] Without assigning NQC values to BTM SPS and VPPs or integrating those

[19] CEC, Final 2025 Integrated Energy Policy Report (July 15, 2026), p. 54.
[20] Assem. Bill No. 825 (2025-2026 Reg. Sess.).
[21] *See, e.g.,* D.23-02-040, Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) And Transmitting Electric Resource Portfolios To California Independent System Operator For 2023-2024 Transmission Planning Process (February 28, 2023)
[22] *See* U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update (January 2025), p. 10 ("VPPs can address system constraints at the generation level (e.g., serve peak demand with storage DERs), at the transmission level (e.g., reduce peak demand when utility-scale supply

resources into LSE portfolios, the Commission fails to meet its requirements to consider renewable alternatives to transmission as Section 454.57(e)(4)(B) requires.[23]

5. If the Commission were to implement the proposal in this ruling, should the need determination be based on specific identified resources or resource attributes? How (in general) and how (specifically) should the procurement need be expressed?

Eligible resource categories should expressly include aggregated BTM SPS and other VPP portfolios. Other proceedings and pilot programs for BTM resources at the Commission and the California Energy Commission should be used to inform the RCPPP. The Commission is examining BTM and distributed energy resources in R.25-09-004[24] and R.21-06-017; [25] the Commission's Emergency Load Reduction Program includes VPP aggregators;[26] and the CEC's DSGS program provides funding for VPPs.[27]

The Commission should create a separate attribute category available to resources that reduce load within constrained local areas without the need for new transmission. The marginal cost of new transmission can be specifically calculated and quantified and the IRP proceeding should include specific analyses of the cost of new transmission attributable to each resource type in its modeling. The Commission's current modeling incorrectly does not recognize the avoided transmission benefits of BTM SPS and VPPs. These resources are undervalued and only treated as demand side resources that reduce load, rather than acknowledging that unlike demand

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is limited by transmission constraints), and distribution level (e.g., shift peak demand that threatens to exceed the safety limits of local equipment to earlier or later in the day).").

[23] Pub. Util. Code § 454.57, subd. (e)(4)(B).

[24] R.25-09-004, Order Instituting Rulemaking to Enhance Demand Response in California (Filing date September 18, 2025).

[25] R.21-06-017, Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (Filing date June 24, 2021).

[26] CPUC, Emergency Load Reduction Program (last accessed August 14, 2026), available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program (listing as eligible "Aggregators of Virtual Power Plants, i.e. a company that can aggregate and control resources such as batteries across multiple customer locations.")

[27] California Demand Side Grid Support, Frequently Asked Questions (last accessed August 14, 2026), available at https://dsgs.olivineinc.com/faq/.

response programs, for example, BTM SPS and VPP resources supply energy directly to the grid.

If BTM SPS and VPPs are excluded from resource accreditation, the default will be utility-scale procurement regardless of whether BTM resources would be cheaper or faster to deploy. Such an outcome would fail to comply with section 454.52's mandate to minimize impacts on ratepayer bills to the maximum extent reasonable.[28]

6. Comment on whether this ruling's proposal is workable in its relationship to any potential CPE procurement for LLT resources.

Central procurement should remain limited to resources that meet the statutory criteria and that cannot be procured more economically or feasibly by LSEs or through aggregated customer resources. The RCPPP should not use LLT procurement as a reason to overbuild and should first determine whether any resource need can be met with BTM SPS and VPPs, generation resources which remain more affordable, avoid the need for new transmission lines, and include other local benefits. Further, BTM SPS and VPPs would meet the Commission's requirements under section 454.57(e)(4)(B) for the Commission to consider as part of the IRP cost-effective and feasible alternatives to transmission, like energy storage and renewable energy resources.[29]

7. Comment on the proposal for a smaller buffer than included in the Staff Proposal from April 2025.

No automatic buffer should be adopted. The 0.1 LOLE standard and the RA planning reserve margin already address potential uncertainties. The Commission recently increased the PRM to 18% for 2026 and 2027, with extensions of the effective PRM (additional procurement

[28] Pub. Util. Code § 454.52, subd. (a)(1)(D).
[29] Pub. Util. Code § 454.57, subd. (a)(1)(D).

required from June-October).[30] In the last several years, the Commission has repeatedly increased the PRM, at considerable ratepayer cost. At the very least, the increased PRM ensures an excess of reliability and eliminates the need for any additional "buffer" in the IRP. Adding one percent without quantifying the potential overlap with the PRM creates a costly recurring unnecessary expense, rather than demonstrably improving reliability. The Commission remains obligated to minimize impacts on customer bills;[31] any buffer would conflict with the Commission's duty and its stated affordability objectives.

8. **Is it appropriate to require the LSEs to procure resource and/or resource attributes with minimum and maximum levels within a range (e.g., 80-120 percent, 40-150 percent)? Propose appropriate minimum and maximum ranges, provide your rationale, and/or explain why this proposal is unworkable.**

Rigid bands should not be adopted. Instead, the Commission should test minimum and maximum requirements against procurement availability and total costs imposed on ratepayers. The Commission should evaluate the proposed bands in the R.25-06-019 proceeding. Maximums can prevent over-reliance on a saturated resource, but they can also block a lower-cost portfolio and invite penalties even when the overall system need has been met. For minimums, the Commission should ensure that it sets a resource minimum for BTM SPS and VPPs to ensure that these valuable resources are procured by LSEs.

9. **Comment on this ruling's proposal for need allocation to specific LSEs.**

The Commission should ensure that it accurately considers the characteristics of individual service territories, rather than merely assigning a proportional share of need based on

[30] D.25-06-048, Decision Adopting Local Capacity Obligations For 2026-2028, Flexible Capacity Obligations For 2026, And Program Refinements (June 27, 2025), p. 123 (OP 6).
[31] Pub. Util. Code § 454.52, subd. (a)(1)(D); Pub. Util. Code § 747.

the Integrated Energy Policy Report.[32] San Diego constitutes a load pocket[33] with distinctive load characteristics and load growth.[34] San Diego lacks the legacy hydroelectric resources that other IOUs have, which serve to buffer against other higher costs electricity sources for their ratepayers.[35]

The Commission should carefully evaluate the extent to which data centers, which are responsible for significant predicted load growth in the 2025 IEPR,[36] will materialize in utility service territories. San Diego Community Power stated in its recent IRP that it does not predict the same level of data center load as predicted by the Energy Division, and that the Energy Division's projected data center load will lead to "significant additional procurement"[37]—which would merely pose unnecessary costs on San Diego's ratepayers without increasing reliability.

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[32] ALJ Ruling, p. 9-10.
[33] Committee on Energy and Commerce: United States Congress, The Energy Policy Act of 2005: Hearings Before the Subcommittee on Energy and Air Quality of the Committee on Energy and Commerce House of Representatives (2005) p. 225 ("A load pocket is typically a small region of the grid that has limited ability to import power because of transmission constraints. New York City, San Francisco, and San Diego are examples of load pockets… However, load pockets generally exist because it is difficult to site new generation or to build new transmission into the constrained area.").
[34] California Energy Commission, California Energy Demand, 2024-2040, available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0 [as of August 5, 2025] (Forecast Files, Baseline Energy Demand Files and Hourly Energy Demand Files provide data for the IOUs including SDG&E. The distinctive position and context of SDG&E can be found, for example, in Baseline Energy Demand, Forms 2.2 and 1.5; the distinctive load shape and sensitivity to policy assumptions in the various scenarios can be found in the Hourly Energy Demand Files).
[35] Costs for hydro are an order of magnitude less than for fossil or nuclear. *See* Southern California Edison Company, 2024 FERC Financial Report Form No. 1 and Others and Supplemental Form 3-Q: Quarterly Financial Report: Annual Report of Major Electric Utilities, Licensees, p. 406, available at https://ecollection.ferc.gov/submissionDetails/238295; *see also* Pacific Gas and Electric Company, 2024 FERC Financial Report Form No. 1 and Others and Supplemental Form 3-Q: Quarterly Financial Report: Annual Report of Major Electric Utilities, Licensees, p. 406, available at https://ecollection.ferc.gov/submissionDetails/238830 [as of August 11, 2026].
[36] CEC, Final 2025 Integrated Energy Policy Report (July 15, 2026), p. 54 ("The baseline consumption for the planning forecast includes 32,630 GWh of data center load growth from 2024 to 2045, and the local reliability scenario includes 49,626 GWh of data center load growth over the same period.").
[37] R.25-06-019, San Diego Community Power: 2026 Integrated Resource Plan (August 10, 2026), p. 7.

At the least, the Commission should develop a more robust evidence-based record before imposing a rough proportional need percentage to San Diego. The data shows that many data centers are likely to be located in the service territory of publicly owned utilities, which have substantially lower rates.[38] The Commission should avoid assigning procurement to San Diego ratepayers for data centers that are likely to be located elsewhere to avoid unnecessarily increasing rates to be borne by San Diego utility customers.

10. Comment on the proposed requirement for 100 percent of required resources to be under contract three years out.

A uniform rule is not reasonable. Requiring that resources be "under contract," with a contract defined as a minimum ten-year term, to demonstrate compliance three years before the online deadline,[39] will render procurement of BTM SPS and VPP resources impossible. The proposed requirement, as written, assumes that contracts will be for utility-scale resources, and excludes resources with shorter development timelines and that rely on customer enrollment. PCF recommends that the Commission adopt an alternative compliance process for BTM SPS

[38] Stanford University Bill Lane Center for the American West, Thirsty for power and water, AI-crunching data centers sprout across the West: With promises of jobs and hopes for tax breaks, server farms are reshaping local grids, plumbing, and politics. Are they a boon for communities, or a burden? (April 8, 2025), ("For data centers, the attraction of Santa Clara, an industrial city in Silicon Valley that was once a chip-making hub, is not tax breaks but cheaper power. The municipal utility, Silicon Valley Power, charges less than Pacific Gas & Electric, the large regional utility."), available at https://andthewest.stanford.edu/2025/thirsty-for-power-and-water-ai-crunching-data-centers-sprout-across-the-west/; American Economic Liberties Project, Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Overcharging the Public (January 2025), p. 2 ("Over the last three years, IOU residential electricity rates have increased 49% more than inflation. In contrast, their publicly owned counterparts have increased 44% less than inflation. In some states, the contrast is even more stark. Investor-owned San Diego Gas & Electric's residential rate increased by 78%, to over 45 cents per kilowatt-hour (kWh) between 2020 and 2023. Similarly sized Sacramento Municipal Utility District's average residential rate rose less than inflation and, at less than 17 cents/kWh, is barely one-third of SDG&E's."), available at https://www.economicliberties.us/wp-content/uploads/2025/01/20250102-aelp-ror-v5.pdf.

[39] ALJ Ruling, p. 11.

and VPPs, under which an LSE can demonstrate compliance through a verified portfolio containing information about customer enrollment, rather than requiring ten-year contracts.

11. Comment on the proposed requirement for 100 percent of required resources to be online within five years from the date the need is identified and allocated.

The inclusion of a five-year target underscores the presumptions of large scale and utility-owned projects inherent in the proposal. The five year deadline should be an outer limit, rather than an inflexible rule across all resource categories. The Commission should allow BTM SPS and VPPs to be available on a shorter time frame, given that distributed solar and storage typically have substantially shorter development and interconnection timelines than transmission-dependent utility-scale resources.

12. Comment on the reasonableness of the proposed cadence and sequencing of work to support the proposed framework, including (but not necessarily limited to) ELCC development, net CONE calculation, and procurement data filings.

After the CEC adopts the IEPR load forecast, the Commission should determine during the PSP and TPP base case portfolio creation how much of any procurement need can be met with BTM SPS and VPPs. As resources that generate dispatchable energy, and avoid transmission costs, BTM SPS and VPPs should be assigned the same incentives in the IRP program as utility-scale resources. Accordingly, aggregated BTM SPS and VPPs should be assigned an NQC value and included in PSP and TPP portfolios.

13. Comment on the reasonableness of using marginal ELCC accreditation toward the procurement requirements for the resources identified in this proposal.

Marginal ELCC is useful for comparing incremental capacity contributions in a changing portfolio, but it should not be the sole metric for all resources. The Commission has recognized unresolved issues in valuing BTM SPS resources for RA.[40] But the CAISO has nevertheless

[40] D.20-06-031, Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program (June 30, 2020), p. 32.

implemented a framework for DER aggregations in wholesale markets, which they have since modified to comply with FERC Order 2222.[41] Aggregated BTM resources are of increasing importance, and yet the Commission's consideration of BTM SPS and VPPs in the IRP and RA proceeding has stalled.[42] BTM SPS and VPPs should be allowed to meet procurement requirements under any accreditation model, and the implemented accreditation model should include the avoided transmission costs and locational reliability value that BTM resources provide.

The marginal ELCC methodology can be well-suited to crediting BTM resources—but only if the Commission takes steps to calculate it. The Commission should direct that future marginal ELCC studies include resource categories for BTM SPS and VPPs. These resources can provide reliability contributions comparable and more cost-efficiently to utility-scale battery storage.[43] Publishing these marginal ELCC values alongside the utility-scale values, five years in advance of compliance deadlines, would give LSEs the certainty they need to invest in BTM programs. Under the current framework, LSEs have no way to quantify the reliability value of their VPP investments for procurement planning purposes. Marginal ELCC values for BTM SPS and VPP categories would directly address this barrier.

[41] FERC, Order No. 2222 Explainer (noting CAISO implementation complete as of Nov. 2024), https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy .

[42] *See e.g.* D.22-06-050, Decision Adopting Local Capacity Obligations For 2023-2025, Flexible Capacity Obligations For 2023, And Reform Track Framework (June 24, 2022), p. 45-55 (Reiterating the unreasonably onerous requirement that a particular set of questions must be answered by parties before a QC value can be granted to BTM SPS resources).

[43] Brattle, Real Reliability: The Value of Virtual Power (May 2023), p. 5, available at https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf (demonstrating that 400 MW of resource adequacy could be provided by VPPs at a fraction of the price compared to battery storage).

14. Comment on the proposal to penalize non-compliance with online resource requirements using a net CONE calculation.

PCF recommends that penalty revenue collected from LSEs that fail to meet their total RCPPP obligation be directed to a dedicated fund supporting distributed-resource and VPP deployment, rather than returned as a general ratepayer credit. Doing so would ensure the enforcement mechanism itself advances the resource diversification goal that the Section 2.6 penalty framework is designed to protect.[44]

15. Comment on the proposal to penalize failure to procure a minimum of non-lowest-cost resource procurement at the level of the highest-cost marginal resource.

BTM SPS and VPP should be added as a source of lowest cost resource procurement. Any penalty structure should include an assessment of whether an LSE procured BTM SPS and VPPs as a threshold cost screen.

16. Comment on the proposal to penalize non-compliance with contracting requirements with an administrative penalty and suggest a basis for this calculation.

PCF reserves the right to comment in reply.

17. Comment on the proposal to move to a four-year interval for consideration of individual LSE IRPs.

A full four-year filing cycle could reduce administrative burden but waiting four years to adopt and refine IRP requirements would prove too slow and too long a time given volatile load forecasts, changing federal and state policy, and rapid DER adoption. Aggregated BTM SPS and VPPs are a rapidly developing energy supply, which has become increasingly accessible and deployable at cost-effective prices. Thus, moving to a four-year IRP schedule, especially as the sole planning update, would result in out-of-date information and the potential failure to deploy

[44] ALJ Ruling, p. 14 ("The purpose of this portion of the penalty structure concept is to dissuade LSEs from procuring only the lowest-cost resources to meet their total requirements, while leaning on the system (and the other LSEs and their customers) to procure the more expensive resource types.").

new or rapidly advancing technologies or resources like BTM SPS and VPPs. If RESOLVE's distributed-resource inputs are stale by the time the Commission adopts a PSP portfolio, the model may systematically under-select aggregated BTM SPS and VPP resources.

18. Comment on the relationship of this proposal to the FERC Order 1920 proposals.

The Ruling states that it assumes that CAISO's proposal to move to a two-year TPP cycle will be approved by FERC, pursuant to FERC Order 1920.[45] Even if CAISO's TPP process moves to a biannual schedule, the Commission should retain annual updates, including new, annual reporting on the implementation of BTM SPS and VPPs. A focus only on new transmission assumes regional and not local resource development and deployment, which would be inconsistent with the Commission's mandates under section 454.57(e)(4)(B).[46] Annual updates will ensure that the Commission has accurate information about important and rapidly developing local and quickly deployable renewable resources.

19. Comment on the relationship of this proposal to the RA program.

Both the RA and IRP proceedings, including this RCPPP proposal, inappropriately fail to determine and assign an NQC value for aggregated BTM SPS and VPPs and thus do not include these resources as part of procurement requirements. Consequently, LSEs have no incentive to develop these resources, or other electricity generating BTM resources. Section 454.57(e)(4)(B) requires the Commission to consider "cost-effective and feasible alternative to transmission capacity expansions, including the use of energy storage resource, renewable energy resources, or zero-carbon resources" as part of the IRP process.[47] The Commission should consider and

[45] ALJ Ruling, p. 15.
[46] Pub. Util. Code § 454.57, subd. (e)(4)(B).
[47] Pub. Util. Code § 454.57, subd. (e)(4)(B).

include BTM SPS and VPPs as zero carbon resources in order to meet its requirements under section 454.57(e)(4)(B).

BTM SPS and VPPs provide additional benefits beyond demand response because these resources generate electricity, rather than just reduce demand. And yet, the Commission has determined demand response to be eligible for an NQC value,[48] while BTM SPS and VPPs are not. Current RA and IRP forecasts model BTM SPS and VPPs as demand reducing resources, rather than acknowledging their generating power.[49]

Numerous programs emphasize the growing importance of BTM SPS and VPPs, and yet no method exists in California to require LSEs to procure BTM SPS and VPPs. The DSGS program provides financial incentives for VPPs, but the state-funded incentive program could disappear entirely if not renewed. [50] Instead, if BTM SPS and VPPs were assigned a QC value, and incorporated in TPP and PSP portfolios, LSEs would have a consistent motivation to develop these resources. Similarly, FERC Order 2222 allows VPPs to participate in California's wholesale markets,[51] but LSEs still cannot meet their RA and IRP obligations with VPPs because the Commission has not yet allowed these resources to be assigned an NQC value.

[48] Commission, Load Impact Protocols (last accessed August 14, 2026), available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/copy-of-demand-response-dr/demand-response-load-impact-protocols ("The Load Impact Protocols (LIPs) are used to estimate ex-ante Qualifying Capacity (QC) and establish RA-eligible QC for DR resources.").
[49] Commission, Inputs & Assumption: 2022-2023 Integrated Resource Planning (IRP) (October 2023), p. 54, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf.
[50] California Demand Side Grid Support, Frequently Asked Questions (last accessed August 14, 2026), available at https://dsgs.olivineinc.com/faq/.
[51] FERC, Order No. 2222 Explainer (noting CAISO implementation complete as of Nov. 2024), https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy .

20. Comment on the relationship of this proposal to the RPS program.

The RPS program is not designed to promote VPPs.[52] As a result, RCPPP may be the first Commission program with a genuine opportunity to create a consistent incentive to procure VPPs and acknowledge the reliability and clean-energy value VPPs provide. The Commission can use the RCPPP to establish, for the first time, an NQC value for distributed resources that have otherwise been unreasonably absent from the Commission's clean-energy procurement framework.

21. Please comment on anything else that is not already covered in the list above.

PCF continues to recommend that the Commission close this proceeding and transfer any RCPPP issues to R.25-06-019, the new IRP proceeding. As shown by PCF's analysis and the recommendations above, numerous and diverse issues now exist and could evolve rapidly in the future, all of which should more fully be considered in a single proceeding. Examples of rapidly evolving issues include the widely varying estimates of electricity demand, shifting state and federal policies, and volatile energy prices. The Commission should not layer additional procurement responsibilities on California LSEs without a thoroughly developed evidentiary record.

The Commission should also coordinate the development of a QC value for BTM SPS and VPPs with Rulemaking 21-06-017, the High-DER proceeding. Incorporating or coordinating with the High DER proceeding's existing record, rather than developing a duplicate record in this proceeding, would promote consistency and administrative efficiency and enable the

[52] *See* Commission, RPS Compliance and Reporting, (last accessed August, 14, 2024), available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/rps-compliance-and-reporting (RPS grants renewable energy certificates to generating facilities, but VPPs generate their reliability benefits from being aggregations of various BTM resources).

Commission to act more quickly to take advantage of these low cost reliable resources like other states have done.[53]

The most important change this Commission can make—a prerequisite to any meaningful BTM inclusion in the RCPPP—is to modify the RESOLVE model to treat BTM SPS as optimizable supply resources rather than fixed demand modifiers. The Commission must recognize that its RESOLVE model remains systemically biased toward front-of-meter resources and produces PSP portfolios that are more expensive than necessary and reverse that bias to evaluate all resources, including DER resources.

The first RCPPP compliance cycle (with a proposed deadline of June 1, 2033)[54] provides sufficient lead time to implement PCF's proposed suggestions. We recommend the Commission direct Energy Division to:

(1) Complete a study by December 2027 examining how BTM SPS and VPPs can be incorporated into RESOLVE as supply, including appropriate cost assumptions and dispatch profiles;

(2) Incorporate the updated BTM modeling into the RESOLVE modeling underlying the February 2028 PSP portfolio adoption; and

(3) Report to the Commission in the 2028 IRP cycle on the quantity of BTM SPS and VPPs identified by RESOLVE as cost-effective.

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[53] *See* PV Magazine, The Virtual Power Plant Era Has Arrived (June 29, 2026), available at https://www.pv-magazine.com/2026/06/29/the-virtual-power-plant-era-has-arrived/. The National Association of State Energy Officials has developed standardized tools by which states can assess DER resources. See NASEO, OpenBCA NSPM-Based Benefit-Cost Analysis Model for Grid-Edge Resources (last accessed August 14, 2026), available at https://www.naseo.org/nesp/openbca-tool.

[54] ALJ Ruling, p. 17.

III. CONCLUSION

PCF recommends that the Commission include BTM SPS and VPPs as supply side resources in RESOLVE, incorporate the resources in the PSP and TPP portfolios, and mandate procurement of these resources as part of the RCPPP. Customer-sited generation is the cleanest and most affordable supply resource available to California ratepayers. These recommendations are consistent with the framework's stated goals, SB 350's least-cost mandate, and California's long-term clean energy and affordability objectives. The RCPPP should recognize the benefits of BTM SPS and VPPs and incorporate these resources as requirements in every LSE portfolio.

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