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June 11, 2021

Energy Division,
California Public Utilities Commission
R.12-06-013 service list

350 Bay Area informal comments on the May 25, 2021
Advanced DER & Demand Flexibility Management Workshop

350 Bay Area commends Energy Division staff for their detailed and thoughtful work presented in the May 25th Advanced DER & Demand Flexibility Management Workshop and strongly supports this effort. Attention to the capabilities of advanced distributed energy resources (DER), flexible load management and load modifying demand response, coordinated with system-wide retail rate reforms, have enormous untapped potential.

Individual components of these proposals have been brought forward by parties over the past decade and demonstrated in numerous CEC EPIC pilots in California, and by utilities, equipment providers, and national laboratories beyond California. With this foundation, regulatory agencies have the opportunity and obligation to leverage associated synergistic goals and technical capabilities to greatly increase the efficiency and optimization of electric grid operation. Localized and regional coordination of energy demand, generation, and storage provides enormous savings to ratepayers in both avoiding costly traditional infrastructure investments and mitigating customer impacts while increasing reliability and resilience.

It cannot be over-emphasized that ease of customer participation is absolutely essential and must be prioritized. The use of "smart" devices, easy enrollment, and simple low cost set up will make an enormous difference in customer participation and results. From a customer perspective, "set and forget" systems that optimize in response to grid signals without requiring customer attention have consistently been demonstrated to deliver dramatically broader and deeper results, and allow for very fast response. This maximizes benefits to both participating and non-participating ratepayers. The proposal's focus on simplicity without direct customer participation in CAISO markets or complex contracts is a critically important and laudable feature.

This proposal is well aligned with the draft 'Utility Costs and Affordability of the Grid of the Future' ("White Paper"), developed by the California Public Utilities Commission (CPUC) and released February 16, 2021. We support the CPUC in taking this strategic approach to forecasting electric rates over the next decade in order to understand the impact of different programs and components of the rate base on affordability, equity, and the climate crisis.

Staff have done a great job of addressing customer outreach, opt-in/opt-out, and ease of use through automated signaling (through existing AMI and web-based pathways, and also through low cost wide area radio signaling) to optimize for both customers, the general rate base, and societal value. As noted in the workshop, while implementation is no small task, it really isn't that complicated and is less complex than many commercial data activities, and other commercial sectors have clearly demonstrated the value and efficiencies realized in optimization of resources and automated targeted customer engagement, especially where the "customer" is recognized as an aggregation of flexible energy loads and resources that responds to signals. We emphasize that you just need to make the value available and loads will respond.

We applaud Energy Division staff for the proposals for a demand-side UNIDE (unified universal dynamic economic) signal, Opt-in Real time pricing option, matching capacity charges with coincident demand, and bi-directional pricing for load and exports (which captures capacity value). These approaches properly align with the principle of associating charges with cost causation while promoting equitable access for customers to meet their individual needs.

Likewise, the staff proposals recognize and incorporate critical concerns over CAISO market integration, and command and control of DER, as well as avoiding frequently debilitating issues of counterfactual measurement and integration into planning and forecasting. Additionally, while the DER Avoided Cost Calculator (ACC) is an important tool in program evaluation, reliance on real time locational values where practical is inherently more accurate than the more generalized historic value embedded in the ACC.

In the above referenced CPUC White Paper, Energy Division staff and their colleagues are also to be strongly congratulated for their analysis (and the detailed information provided) on the dramatic increase in transmission spending and the utility rate base over the past five years among California's three Investor Owned Utilities. For example, between 2016 and 2021, PG&E's transmission rate base increased 45.0% from $5.846 billion to $ 8.476 billion. (draft White Paper Table 7 p36).

However, it appears that the use of a fixed capacity constraint in the proposed staff methodology ignores the DER value in reducing multiple transmission related costs. Building upon the methodology which is excellent and detailed in other respects, and given that transmission costs are the fastest rising cost component and a significant portion of total rates, finding a way to reflect actual realized ratepayer transmission value in rate design and real time pricing incentives is strongly warranted. Incorporating avoided transmission associated costs in the proposal will improve the customer participation incentive and therefore both the response and ultimate cost effectiveness of this effort.

While transmission cost *recovery* is FERC jurisdictional, cost *causation* and transmission planning and investment happens within California. The Transmission Revenue Requirements are driven by CPUC, CEC and CAISO approved transmission planning process, and these revenue requirements are the basis for the FERC approved transmission charges; reducing the total future revenue requirements directly reduces customer rates, and this should be incorporated. DER deployment and dispatch that frees up existing transmission capacity and can thereby avoid or reduce the need for new transmission capacity, as well as avoiding congestion and access to least cost generation bids, clearly has direct ratepayer value. UNIDE based rates and signaling will optimize the operational profiles of customer's flexible loads and generation. Even today, without smart signalling and response, we have seen direct examples of major ratepayer savings from added DER such as energy efficiency and rooftop solar in CAISO's 2017 TPP - the prior planned transmission projects had already accounted for reductions in transmission need due to forecast DER levels, but DER deployment <u>above and beyond</u> that forecast was the primary factor in the cancellation of numerous projects. CAISO found that increased growth in energy efficiency and rooftop solar above what had been forecast led to the cancellation of numerous unneeded transmission projects in 2017-18 alone, saving ratepayers not just the $2.6 Billion in capital costs, but over $10 Billion in future operations, maintenance, and return on equity costs. DER offer a clear opportunity to slow the dramatic acceleration in transmission cost experienced by California ratepayers. FERC rules strongly support aligning cost allocation with cost causation, and this should be respected as long as it continues to be balanced with strong social and environmental equity considerations.

Two separate national studies (from Princeton University and Vibrant Clean Energy) have shown that increased interconnection on the distribution grid of clean DER's can result in enormous cost savings. The Vibrant Clean Energy modelling, which optimized DER for least cost, also showed a decrease in electricity rates over time as a result of this optimized DER deployment, which would be incented by the current staff proposal. Distribution planning co-optimization results in US national cumulative system-wide savings of $301 billion by 2050 ("BAU" vs "BAU-DER"), which rises to $473 billion when considering a clean energy standard ("CE" vs "CE-DER"). If a clean electricity mandate was implemented by 2035, rather than the modeled 2050 (and the US could deploy enough generation), the DERs would bring forward the cost savings observed by 2050 to 2035, since they enable more clean utility-scale variable generation to be deployed efficiently.

> "Even though the electricity system is undergoing substantial change in the modeling scenarios, the total system costs are subdued and fall across all scenarios through 2050. This is because low-cost renewables and natural gas help reduce wholesale electricity costs. There are costs to upgrade the distribution infrastructure, but there are also cost savings from deferment of upgrades to the transmission-distribution interface (or connection points) as well as removing unnecessary utility-scale capacity reserved for peaking needs. Since the modeling reduces utility-observed system peaks by around 16% by 2050 (due to the DER coordination) compared with "Business as Usual BAU", a significant fraction of utility-scale peaking and capacity is avoided."

Implementation of California's forward thinking and progressive energy efficiency standards has successfully kept average household energy use flat over the past four decades while nationally average household energy use has doubled over the same period. This has not only resulted in ratepayer savings from lower energy consumption, but has greatly reduced statewide electric utility infrastructure capacity requirements, and realized associated emissions reductions. Peak load mitigation and on site generation can likewise reduce the utility infrastructure capacity requirements associated with increased electrification of our building and transportation sectors.

The urgency of this proposal to recognize and unleash the value of DR and DER became evident during this week's workshops beginning the 2022 update to CARB's Scoping Plan, which lays out how California can meet our climate goals. CARB, CEC, and E3 modelling demonstrates the need for substantially accelerated growth of renewable generation and storage over the next 10 years. Currently the SB 100 modelling efforts consider "utility solar" as a single category and results in assumptions of substantial needs for additional transmission. As we discuss above, planning for transmission would benefit from better assessment of what portion of renewable generation and storage might cost effectively be sited either BTM or In Front of the Meter on the Distribution Grid where it could contribute to strategic DER and flexible demand management.

Given the increasing role of transmission costs in California electricity rates, and the need for greater CPUC oversight of transmission investments within the state (mentioned by Paul Phillips during the June 10, 2021 workshop), time is of the essence in developing the staff proposal and subsequent proceeding(s).

We appreciate Energy Division's draft proposal as previewed in the workshop and consideration of these comments, and we look forward to the forthcoming White Paper and a Rulemaking on this topic.

Sincerely,

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On behalf of 350 Bay Area
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