BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 (Filed June 24, 2021)

CENTER FOR BIOLOGICAL DIVERSITY, THE CLIMATE CENTER, 350 BAY AREA, THE CLEAN COALITION, VOTE SOLAR, AND SIERRA CLUB OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS ON TRACK 1 PHASE 1

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Pursuant to Administrative Law Judges Hymes and Lakhanpal's April 6, 2023 Ruling, the Center for Biological Diversity, The Climate Center, 350 Bay Area, Vote Solar, Sierra Club and The Clean Coalition provide the following opening comments.

I. INTRODUCTION

The Center for Biological Diversity, The Climate Center, 350 Bay Area, Vote Solar, Sierra Club and The Clean Coalition support the Commission's stated intention in this OIR "to optimize the integration of millions of DERs within the distribution grid while ensuring affordable rates." Optimizing distributed energy resources ("DER") integration and DER value to society requires a regulatory framework that offers meaningful opportunities for grid operators, ratepayers, and DER owners to utilize the full capabilities of all available DER, including being compensated for services to the electric power system and contributions to California's urgent goals for clean energy production, climate resilience and energy justice. Adoption and timely implementation of favorable DER policies will stimulate cost-effective DER deployment and incentivize DER performance that supports grid reliability, which in turn will affect the nature and cost of power system investments needed to prepare for the high-DER future. Clear incentives and information access for non-utility DER deployment and performance that align with reliable grid operation will reduce the need to expand grid capacity, thus reducing system costs for ratepayers.

These considerations frame the responses we provide here to the Commission's questions. Central themes running through our responses urge the Commission, in this proceeding, to:

> (1) Establish sustained communication with local communities and community-based organization ("CBOs") to understand community energy needs and priorities and identify how they can benefit from local DER deployment in an ongoing manner and integrate feedback into Distribution Planning;
>
> (2) Expand opportunities for customer- and third-party-owned DER to contribute and be compensated for providing grid services and societal benefits; and
>
> (3) Direct the IOU distribution utilities to implement transparent planning processes and information access provisions to enable those opportunities to be realized.

While we realize the extent of work required to implement these proposed changes to planning processes and subsequent investment decisions, we emphasize that such efforts are not unprecedented. In Oregon, for example, Portland General Electric and Pacific Power have recently taken similar actions, including development of an "Equity Map" that overlays energy burden data onto their hosting capacity/Distributed Generation Evaluation map, a non-wires solution selection and analysis process that incorporates equity factors, a Community Input Group to solicit feedback on their plan and process, and a community benefits test and other revisions to traditional benefit-cost analysis methods.[1] The Oregon Public Utilities Commission has also required both utilities to propose two projects that "address community needs" in a future filing.

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[1] Institute for Market Transformation, Redistributing Power to Communities in Oregon (April 18, 2023), *available at* https://www.imt.org/news/redistributing-power-to-communities-in-oregon/.

II. RESPONSES TO ALJ RULING QUESTIONS

Utility Distribution Planning Process (DPP) Improvements

1. **Considering the Utilities' existing Local Planning Engagement practices, as filed in response to the March Ruling, what improvements should be made to the Utilities' DPP in terms of engagement and communication with tribal, local and regional planning entities?**

   The DPP should continuously engage with communities to determine community needs that a High DER future can meet. As requested in prior workshops and comments, the Commission should develop a Community Engagement Plan that spans Tracks 1 and 2 of this proceeding and coordinate local engagement efforts with the CEC.

At the May 23, 2022 Track 2 kickoff workshop, parties first requested a Community Engagement Plan, identifying the opportunity to "put at the front of the queue communities with historically low DER adoption rates."[2] Those parties stressed that this community engagement plan should determine how a high DER future can serve the needs of disadvantaged communities ("DACs") and other environmental and social justice ("ESJ") community residents.[3]

Then, in our opening comments on the Draft Track 2 Outreach Plan, we again commented on the need for a holistic Community Engagement Plan that spans both Tracks 1 and 2 of this proceeding and is coordinated with the CEC's community engagement efforts and ongoing work in the CEC's parallel Order Instituting Investigation on DER ("DER OIIP").[4]

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[2] *See* Proposed Process Amendments to Center Community Engagement and Achieve Environmental and Social Justice Goals (May 3, 2022) *available at* https://gridworks.org/wp-content/uploads/2022/05/Center-for-Biological-Diversity-presentation-DSO-Evaluation-Kickoff-Workshop.pdf, slide 3, citing Inequitable access to distributed energy resources due to grid infrastructure limits in California, Brockway, Conde and Callaway, *available at* https://escholarship.org/uc/item/6pc2k2tv

[3] *Id.* at slide 4.

[4] *See* CEC DOCKET No. 22-OII-01, *available at* https://www.energy.ca.gov/filebrowser/download/4010; Center for Biological Diversity et al. Opening Comments on Draft Track 2 Engagement Plan at 6 ("There is significant overlap between CPUC proceeding Tracks and related CEC efforts in identifying, considering and ultimately delivering ESJ community benefits. This warrants close coordination between the CEC and CPUC as well as both Tracks 1 and 2 of the CPUC proceeding and related CEC efforts.")

This Community Engagement Plan should assist in the development of improvements to the DPP as detailed below.

It is critical for the Commission and CEC complementary planning processes to include the identification and integration of DAC resident needs and benefits into expectations of future DER growth. Moreover, Track 1 is currently scoped to create and implement a Community Engagement Needs Assessment to determine what communities want and need from distribution planning.[5] This differs from a *Grid* Needs Assessment. Community needs should drive the DPP and subsequent investment and procurement decisions.

Improvements to DPP local engagement protocols are a key component of identifying those needs and benefits that DER can and should deliver. The Commissions can then tailor and plan for the outcomes of DER deployment strategies to effectively meet those needs. Absent need-and outcome-based objectives for these proceedings, it is reasonably foreseeable that DAC and other ESJ community needs will not be addressed in a high DER future, precluding our ability to meet California's SB 100 and other climate and equity goals.

Vision Element 2B of the DER Action Plan details three planning processes (the CAISO Transmission Planning Process, the Integrated Resources Plan and the Distribution Planning Process) to address "local community and tribal conditions and community needs." The CEC's IEPR Updates and DER OIIP are also relevant sources to consider, as well as any findings from community engagement efforts in Track 2. The overlaps between Tracks 1 and 2 warrant a holistic Community Engagement Plan, versus inefficient piecemealing by bifurcating Track 1 and 2 work. For instance, adequate DPP community engagement efforts will provide more granular information about load in DAC and ESJ communities, a much superior information

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[5] *Supra* note 2, CPUC Workshop Presentation Slide 15.

gathering framework than the current practice of determining this information from interconnection applications that may not wholly convey BTM resources, demand response, energy efficiency or other DER grid solutions.[6]

While we appreciate the IOUs' efforts to engage communities under the current DPP, as SCE notes "[k]ey challenges include *a lack of two-way communication*, along with feedback from some communities that they do not feel that outreach is properly tailored to their needs." In addition, SDG&E notes that "SDG&E identifies and partners with Community Based Organizations (CBOs) to learn appropriate outreach techniques and community insights. In concert with the CBOs, SDG&E goes into the communities to educate them on pressing issues and to garner feedback based on open conversations."[7] While partnering with CBOs to learn appropriate outreach techniques and community insights is a valuable practice, this needs to be expanded beyond one-off opportunities and integrated into the DPP and other planning processes more holistically. Rather than utilities going to communities to educate, utilities or preferably another trusted, third-party entity should be having continuous conversations with communities about their needs as a whole, with the DPP providing one avenue to then incorporate planning to address them. The DPP should be improved to be more proactive than reactive. For instance, SDG&E notes when it comes to DPP engagement directly, "[a] key element of customer engagement that is directly related to the DPP is the new service request process that customers use to request service for new and/or increased end-use loads. Customer engagement ensures

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[6] *See e.g.* PGE Responses at 20 ("Communities currently help inform the DPP by submitting new service applications and through regular and as-needed PG&E engagement."); SDGE response at 12 ("A key element of customer engagement that is directly related to the DPP is the new service request process that customers use to request service for new and/or increased end-use loads"); SCE Response at 19 ("Key challenges include a lack of two-way communication, along with feedback from some communities that they do not feel that outreach is properly tailored to their needs.")

[7] SDG&E response to March Ruling at 11.

that the infrastructure needed to accommodate each load addition can be planned, designed, incorporated into the DPP (via "known loads" included in the load forecast used in the DPP), and ultimately serviced."[8] Relying on communities to process new service requests and then engage on known loads is a reactive way to engage communities. Those with little knowledge or experience in energy work will not know how to engage with this process. Instead, utilities or trusted third parties should be proactive in discussions with communities on their needs, and not assume or require extensive energy and technical expertise to request upgrades or improvements to the quality of their service and longer term needs. Communities know what they need, but may often not be able to participate fully in the utility led processes that can be in-depth, technical and time-consuming.

PG&E reports a similar process of engaging communities on the DPP: "Communities currently help inform the DPP by submitting new service applications and through regular and as-needed PG&E engagement. PG&E will continue to leverage these existing outreach efforts to further improve engagement and communication with local and regional planning entities regarding the DPP."[9] Engagement through submission of new service applications should not be considered efficient or substantial community engagement to fully capture community needs. Only those with the knowledge and ability to file service requests for new loads will be able to participate, foreclosing opportunities to truly understand other community-level needs.

SCE reports a similarly opaque and difficult process by which communities or members can weigh in on planning for DERs stating, "PSA Town halls, hosted regionally to educate stakeholders on the load interconnection process and to encourage customers to engage with

[8] SDG&E Response to March Ruling at 12.

[9] PG&E Response to March Ruling at 2.

SCE sooner in their development process. It also introduces them to available online tools in SCE's data portal, which currently offer total queued generation projects per circuit and substation, and potentially could provide insights on a project-by-project basis in the future".[10] Town halls to educate is not the same thing as ongoing, proactive conversations with community members and organizations on the needs communities face and how the DPP process could be applied to incorporate those needs and requests. Utilities should be responsive to the needs of all community members, not just those who can submit projects or have the technical expertise to weigh in. Allowing insights on a project-by-project basis in the future is a worthwhile endeavor for further discussion, but enabling engagement in a way that is easily accessible and not limited by language, time of day and technical jargon are important aspects to consider. As of now, community engagement with regard to distribution system planning has been significantly one sided, and without clear transparency on how feedback is being valued and incorporated. Establishing clear metrics and transparent reporting for how community feedback is integrated into utility DPP would both improve outcomes and build trust for long-term engagement.

Furthermore, interconnection applications alone may not holistically convey the extent of community needs that can be met by BTM resources, demand response, energy efficiency and other DER grid solutions. A Community Engagement Plan provides the opportunity to not only improve the DPP, but also to ultimately "stack" resources, or create a one-stop shop for varied and complementary DER in the community.

2. **Energy Division's 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work proposed that a consultant conduct outreach to help inform this proceeding. In other proceedings, such as the Microgrids and the Climate Adaptation proceedings, and in the PG&E Regionalization plan, the Commission has required Utilities to conduct outreach and community engagement. Should this proceeding also direct Utilities to**

[10] SCE Response to March Filing at 19.

assume this role? Would outreach by Utilities enable building and maintaining of partnerships with tribal, local, and regional planning entities and ensure community engagement is incorporated into the Utilities' DPP?

Because the IOUs' prior community engagement efforts have not proven successful in ESJ communities, the IOUs should not assume this role. Rather, a consultant with a proven track record of working with ESJ communities and that has developed trust in various ESJ communities should develop a Community Engagement Plan for Tracks 1 and 2 of this proceeding.

The effectiveness of Energy Division's 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work is hindered by the draft's inadequate definition of "community," which skews engagement efforts to maintain the status quo where benefits of energy resources are disproportionately located in more affluent communities. We will comment further on this issue once the Commission opens the comment period for that Draft Scope of Work, but this simply emphasizes the need for the Commission to take a holistic, and not a piecemealed approach to community engagement between Tracks 1 and 2 in this proceeding. It is imperative for the Commission to develop a holistic Community Engagement Plan as detailed in our prior comments.

Since the publication of the Low-Income Barriers Study, several parties have commented *ad nauseum* on the lack of trust between residents of ESJ communities and the IOUs.[11] To eliminate this significant barrier to clean energy resources, several parties have since universally recommended that the Commission adopt the community engagement principles developed in

[11] *See e.g.* SB 350 Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-income Customers and Small Business Contracting Opportunities in Disadvantaged Communities (December 2016) ("Barriers Study") at 48 *available at* https://assets.ctfassets.net/ntcn17ss1ow9/3SqKkJoNIvts2nYVPAOmGH/fe590149c3e39e51593231dc60eeeeff/TN214830_20161215T184655_SB_350_LowIncome_Barriers_Study_Part_A__Commission_Final_Report.pdf.

the Commission's San Joaquin Valley ("SJV") proceeding,[12] whether in the Climate Adaptation Proceeding, the Microgrids Proceeding, or this proceeding. The ESJ Action Plan further includes a tentative work plan action item: "[s]hare *lessons learned*, especially related to community engagement led by CBOs and how to reach residents of ESJ communities, with broader CPUC staff."[13] This action item is intended to achieve Goal 2 of the ESJ Action Plan: "[i]ncrease investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health."[14] The ESJ Action Plan also details discussions between ESJ advocates and Commission Administrative Law Judges seeking input on how to better engage ESJ communities. In discussing various options, the ESJ Action Plan notes that the SJV proceeding "provides a better model" for community engagement.[15] Partnership with CBOs is a key takeaway and model from the SJV proceeding, as the ESJ Action Plan also documents.[16]

By contrast, despite the Commission also requesting parties' input on best practices for community engagement in the Climate Adaptation Proceeding, and parties including the California Environmental Justice Alliance recommending that the proceeding take lessons learned from the SJV proceeding, the Commission still failed to do so, resulting in less than expected community engagement outcomes. In that proceeding, the Commission authorized the IOUs to develop community engagement plans, but did not require partnerships or funding for CBOs, as recommended by the advocates and lessons learned from the SJV proceeding.

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[12] See D.18-12-015 at 80-85 *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M252/K522/252522682.PDF (detailing Community Energy Navigator program and roles and listing criteria to select an appropriate CBO).
[13] CPUC ESJ Action Plan Ver. 2 at 36 (emphasis added)
[14] *Id.*
[15] *Id.* at 58.
[16] *Id.* at 103.

Consequently, the California Environmental Justice Alliance and the Natural Resources Defense Council filed protests to the Advice Letters that proposed community engagement methods. The Commission nevertheless approved those engagement plans and subsequent vulnerability assessments, which remain without the adequate input of CBOs, and the outcome of the assessments is to date unclear.

Similarly, in the microgrids proceeding, R.19-09-009, The Microgrid Equity Coalition ("MEC") participated throughout the summer workshops leading up to the Implementation Plan and provided detailed input to IOUs with the goal of ensuring that the Microgrid Incentive Program ("MIP") Implementation Plan would provide a full and fair opportunity for frontline communities and DACs to participate in the MIP. Specifically, the MEC provided two sets of written feedback to the IOUs and Energy Division staff to be clear about its specific recommendations: the MEC Summary of MIP Implementation Recommendations (Oct. 20, 2021), and the MEC Response to Oct. 26 MIP Presentation (Nov. 22, 2021), and the MEC Response to Oct. 26 MIP Presentation (Nov. 22, 2021).[17] The MEC recommended a detailed proposal informed by the SJV proceeding principles, with major elements aimed at providing community engagement throughout the development of microgrids and how utilities would interact with the communities that would be benefiting from any microgrid developments.[18] They included allowing communities to identify the most essential services needed to be powered by microgrids, an application process that was accessible to frontline and disadvantaged communities including funding up front to enable technical support, and oversight by the

[17] *See* R.19-09-009, California Alliance for Community Energy, California Environmental Justice Alliance, GRID Alternatives, Sierra Club, The Climate Center, and Vote Solar Comments on Proposed MIP Implementation Plan, Attachments 1 & 2 (January 14, 2022).

[18] *Id.* at 4.

Disadvantaged Communities Advisory Group to review scoring of winning projects picked by the utilities and upfront, direct IOU-provided assistance to review project aspects directly with project applicants. The final MIP, however, was far from what the MEC had requested, and despite clear direction for the IOUs to engage alongside potential applicants and communities, there was little to none of that done prior to a determination on the final MIP other than workshops during the proceeding itself.

By contrast, targeted and focused long-term engagement that follows SJV proceeding lessons learned, and adequately leverages CBO relationships have proven far more successful.[19] We summarize the lessons learned: first, community engagement should be informed by a guiding principle; second, community engagement should be conducted by or at least in partnership with CBOs; and third, the Commission should develop adequate funding mechanisms for those subsequent CBO efforts.

Overall, community engagement should avoid placing burdens on the community. It must recognize both input from communities and information to communities. Both are important and interrelated, but the mechanisms for each may be very distinct. Communities should define broad goals and constraints, but not be responsible for translating these into specialized planning applications.

(a) A Guiding Principle Should Inform Community Engagement Efforts.

The SJV Proceeding is largely viewed as the model for successful community engagement. In that proceeding, the Commission ultimately selected clean energy pilot projects under a guiding principle, developed in conjunction with community engagement that occurred

[19] *See e.g.* GRID Alternatives, 2022 Marketing Education and Outreach Plan, *available at* https://gridalternatives.org/sites/default/files/2022-04/DAC-SASH%202022%20MEO%20plan_March%202022%20FINAL.pdf (achieving 82% of Installations Forecast in DAC-SASH Program).

throughout the proceeding. To ensure that community engagement efforts in this proceeding are likewise centered on community voices, this proceeding should include a similar guiding principle, for instance:

> "A [High DER future/DPP Improvements/DSO Model] will advance community benefits including improvements to health, safety, reliability and air quality, and include local hire goals and/or a workforce development plan. Community support is a critical factor and will be considered along with the long-term benefits of improvements to health, safety, reliability, air quality, and reduction of greenhouse gas emissions . . . and ensures bill savings and affordability for participants."[20]

Just as in the SJV proceeding, the Commission should also partner with trusted CBOs to develop and implement the Community Engagement Plan. A meaningful partnership further requires adequate funding.

(b) The Community Engagement Plan Must Be Developed and Implemented in Partnership with Community Based Organizations.

As the SB 350 Barriers Study determined, "[s]ome customers are hesitant to have data about them collected by government agencies," and recognizing "low levels of trust . . . with respect to their energy utilities."[21] Design and implementation of the SJV proceeding pilot projects revealed the extent of this finding, and how partnerships with CBOs could positively contribute to eliminating this significant barrier. Similarly, Goal 5.2 of the ESJ Action Plan specifically "emphasize[s] engagement with CBOs" and the need to "deepen relationships and network connections with community-based organizations throughout the state."[22] The ESJ Action Plan notes how partnerships with CBOs can "deepen impact in ESJ communities."[23]

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[20] This is the guiding principle from D.18-12-015 (at 10) authorizing San Joaquin Valley pilot projects, and replacing "Pilots" with "High DER future," "DPP improvements," or "Distribution System Operator (DSO) Model."

[21] Barriers Study at 48, citing Research Into Action et al, 2016.

[22] CPUC ESJ Action Plan Ver. 2 at 24.

[23] *Id.* at 31.

Overall, "[p]artnerships with CBOs are essential to reaching and benefitting ESJ communities."[24] Furthermore, the CPUC and CEC must "[e]nsure these partnerships are resourced and that CBOs are given room to deploy a variety of strategies to meet community needs,"[25] as discussed below.

(c) The Community Engagement Plan Must Include a Funding Mechanism for Community Based Organization Participation.

The Commission has previously authorized compensating CBOs for vital marketing, education and outreach work "so they are able to accomplish the outreach . . . envisioned."[26] Absent financial support, it is reasonably foreseeable that capacity limitations on CBOs will result in only cursory input, insufficient to set the stage for a high DER future. The Climate Adaptation Proceeding offers one example of cursory input and "checking the box" for community engagement, versus actually leveraging CBO expertise and relationships to further proceeding goals.

We have previously commented on the variety of options that the Commission and CEC can explore to fund community engagement efforts. For instance:

(i) The Electric Program Investment Charge ("EPIC") program. AB 523 allocates at least 25% of the EPIC Fund to support technology demonstration and deployment located in and benefitting "disadvantaged communities" as defined by SB 535, while also dedicating 10% of the fund to activities located in and benefitting 'low-income' communities as defined by AB 1550. In addition, the CPUC is currently considering the IOUs' EPIC 4 Projects that seek to determine "innovation priorities for DACs."[27] Several of the IOUs' proposals target DERs and can similarly target DACs and other ESJ communities. Funding for the current 5-year EPIC-4 cycle exceeds $820 million.

(ii) A pilot funding mechanism for community engagement. This is Action Item 1.2.2. of the ESJ Action Plan: explore concept of a paid CBO pilot program that

[24] *Id.* at 53.
[25] *Id.*
[26] D.18-06-027 at 83-84; *see also* D.18-12-015 at 82-85 ("the [funded] Community Energy Navigators" would be "key to the success" of the pilot program).
[27] *See e.g.* Joint IOU Presentation to DAC Advisory Group (August 2022), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=245082&DocumentContentId=79209

aims to facilitate deeper involvement of CBOs in CPUC programs and processes. This proceeding offers a platform to launch this pilot.

(iii) A Decision in this proceeding can authorize funding through a Request for Proposal process, as in the CPUC San Joaquin Valley Proceeding.[28] Alternatively, the CPUC could also authorize an Advice Letter process to establish a new memorandum account to record and recover costs associated with the development and implementation of a community engagement plan.[29]

Overall, there is a stark contrast when comparing the substantial funding available for "traditional" intervenors in Commission proceedings, such as the intervenor compensation program, or the funding available to members of the Procurement Review Group, and the lack of funding available to solicit community-level input. The Commission and CEC should coordinate efforts to correct this imbalance, adequately value on-the-ground input and expertise, and maximize funding for this potentially significant community engagement effort.

Overall, we reiterate the need for a Community Engagement Plan to drive Tracks 1 and 2 of this proceeding. The Community Engagement Plan should be developed by or at least in conjunction with CBOs to determine how to improve engagement efforts in the DPP for long-term, sustainable and successful engagement.

3. How should the Utilities' local planning engagement efforts on DPP be combined or coordinated with the community engagement efforts in other proceedings?

Generally, other proceeding engagement efforts have not produced intended results. We stress the recommendations from the ESJ Action Plan to follow lessons learned from the SJV proceeding and offer recommendations on how that engagement should be focused. The IOU local planning and engagement efforts on DPP should be combined and coordinated with Track 2 and CEC parallel work, including in the CEC OIIP.

We understand that the local engagement required in this proceeding is a large task, warranting cross-agency collaboration. To achieve the ESJ Action Plan's Goal 2 (increased

[28] D.18-12-015 at 81-83.

[29] *See* R.15-03-010, SoCalGas Opening Comments on Data Gathering Plan Proposed Decision at 2.

investment of clean energy resources to achieve benefits in ESJ communities), the Commission recommends "outreach and engagement" in order to "understand impacts in ESJ communities," leveraging "cross-agency" efforts, and "address ongoing and legacy impacts in ESJ communities in the resilient, clean energy space," by "prioritize[ing] resilient, clean energy investments in ESJ communities." Each of these objectives is rooted in determining community needs or the benefits to communities that clean energy resources, or DER, can deliver — the exact purpose of this and the CEC's DER proceedings. The Commission should authorize a Community Engagement Plan that spans both Tracks 1 and 2 of this proceeding. We will comment on the 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work when the Commission opens the comment period, but for now stress that the Commission should ensure that the winning bidder to more fully develop that Scope of Work should have a history of trust in relevant ESJ communities, the organizational infrastructure to leverage or stack multiple DER offerings, and be able to provide a feasible solution to such a large statewide effort.

We reiterate from prior comments, the following examples of community needs that a Community Engagement Plan should verify and expand upon. We also describe how each community benefit could inform DPP improvements, DSO/grid architecture, or the growth (forecasts) of DER generally.[30]

(i) Economic development, for instance, ownership of DER assets: targeting of behind-the-meter ("BTM") resources can meet this community need. It is critical for planning efforts to determine an equitable (re)distribution process where a high DER future prioritizes each neighborhood receiving a fair share of resources

[30] These examples and descriptions are informed by the SB 350 Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-income Customers and Small Business Contracting Opportunities in Disadvantaged Communities (December 2016).

to move towards a balance between growth and restoration from past injustices.[31] This is consistent with Goal 2 of the CPUC's ESJ Action Plan: "increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health."

(ii) Resiliency: a community resilience hub is an obvious example, but a community engagement plan could go further to determine what other specific DER could be coupled with a resilience hub to meet community needs, for instance:

- Renewable energy and revenue production through small-scale energy projects
- Energy storage and local microgrid development for off-the grid-resilience and disaster recovery strategies
- EV recharging and revenue production
- Neighborhood focused transit options
- Energy resilience planning to ensure social and public health service delivery through crises and disasters
- Energy asset management training and project construction; job placement and workforce development
- Enhancing public health through asphalt heat mitigation (solar parking lot canopies) and extreme heat cooling centers

(iii) Heating and cooling needs in climate zones: it has proven difficult to successfully implement demand response programs in certain climate zones, in particular in DACs and other ESJ communities. Demand flexibility options may face similar barriers that a community engagement plan can specifically target to address.

(iv) Community-specific local air quality concerns: for instance, a particular community is overburdened by diesel particulate matter pollution from trucks or other indirect sources. Focused deployment of medium or heavy duty EVs to replace diesel trucks, with targeted deployment of bi-directional vehicle to grid integration may present a potential solution to meet community and overall grid reliability needs.

(v) Workforce development: a high DER future presents an opportunity for DAC and other ESJ neighborhoods to not just participate in the regional economy as dependent users or purchasers of goods and services, but also as producers of goods and services with the ability to generate revenue that can be reinvested

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[31] *See generally* Hernandez, J., Race & Place in Sacramento, Sept 2021, A report for the City of Sacramento to support preparation of the Environmental Justice Element of the Sacramento 2040 General Plan Update, *available at* https://www.cityofsacramento.org/-/media/Corporate/Files/CDD/Planning/General-Plan/2040-General-Plan/Race_Place_Nov-2021.pdf?la=en

back into neighborhood development.[32] A community engagement plan could serve as an integral component to ensure that circular economic activity is encouraged at the neighborhood level. This includes local workforce development for the construction, installation, and management of certain aspects of DERs.

(vi) Affordability: with a focus on Non Energy Benefits ("NEBs") and social costs, a community engagement plan can help determine cost-effective deployment of DER. Even absent consideration of NEBs, DER still allow for greater electrification and weatherization, which significantly reduce energy bills; as the 2021 CPUC Affordability White Paper notes, managed transportation and building electrification could save a household with above average energy use in a hot climate zone over one hundred dollars a month in total energy costs.[33] And if accurately considering the full range of avoided costs, in particular from avoided transmission, distribution and generation buildout, high DER penetration could benefit all ratepayers.

(vii) Specific cultural marketing, education and outreach needs to achieve a clean energy future: a community engagement plan could complement other state or local outreach efforts to achieve our decarbonization goals. A community engagement plan could help identify additional opportunities to address neighborhood level specific barriers to decarbonization, such as education on how electric cooking appliances do not supplant cultural or traditional cooking practices.

The Community Engagement Plan should determine which proceeding Tracks and which CEC activities cover which outreach, engagement and partnership efforts, with the ultimate goal of determining local needs. Overall, a Community Engagement Plan should develop place-specific information or data that begins to document the energy use in the DACs or other ESJ communities, and investigates potential sites to produce energy locally and maximize multiple DER offerings. Understanding the amount of energy needed in each community, along with the capacity for local energy production to meet those demands brings us closer to itemizing the resources and administrative processes required to put in place the system of soft and hard

[32] *Id.*

[33] CPUC, Utility Costs and Affordability of the Grid of the Future, Figure 38 at 77 (2021).

infrastructure needed for community sustainability, as required by SB 1000, AB 1550, SB 535, SB 350 and other state climate and equity policies.

Demand Scenarios and Planning Horizon

4. **Should different demand scenarios, based on the California Energy Commission's Integrated Energy Policy Report (IEPR) load forecast data and/or other datasets, be used for utility DPP?**

Yes

a. What datasets, and how many scenarios should be used?

The IEPR should continue to serve as the common reference for aggregated demand, a "top down" perspective. Within the IEPR demand scenarios, attention should be given to accounting for the degree of uncertainty in order to balance risk of delays in needed upgrades against the cost of premature investment across likely scenario alternatives. We recommend anticipating for high demand within the planning horizon, but scheduling actual expenditures based on higher certainty and nearer term data to refine project timelines.

Deployment of DER is rapidly changing. The Commission should therefore also explore methods to ground truth IEPR estimates with more updated data, and incorporate sensitivity analyses. For example, DG Stats shows 986 MW BTM storage in 2022,[34] whereas the most recent update to the IEPR records 622MW of BTM storage in 2021.[35]

b. How should regional or local demand be considered in the Utilities' DPP in addition to the IEPR forecast?

In addition to the IEPR demand scenarios, each utility should continue to utilize methods to disaggregate total demand to reflect localized variations in a "bottom up" perspective to refine distribution investment planning.

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[34] DG Stats, *available at* https://www.californiadgstats.ca.gov/charts/

[35] *See* CEC IEPR 2022 Update at 56, *available at* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update.

Data sets used may vary between utilities and should incorporate locally available information. Utilities could be encouraged to utilize information on DER, such as DG Stats, that could signal relevant rapid changes not evident in the current IEPR cycle. Each utility may exercise its own discretion in this process as long as it conforms to Commission guidance and remains subject and responsive to independent review through the Distribution Planning Advisory Group ("DPAG") and an Independent Evaluator. DPP data should include: first, customer-driven, time-series and geospatially granular load and DER adoption forecast methods; second, the use of scenario and probabilistic methods to better capture uncertainty and manage risk; and third, a more holistic view of objectives and metrics for evaluating distribution planning solutions that include not only reliability and economics, but also address resiliency, equity, and carbon emissions. Objectives and metrics should include realization of NEBs and other societal benefits that DER can offer.

5. **How would using different demand scenarios in DPP impact other planning proceedings such as General Rate Case and Integrated Resource Planning proceedings?**

Broadly speaking, using different demand scenarios in the DPP should not significantly impact the GRC or IRP. The Commission should coordinate the DPP, IRP and other related proceedings to maximize the potential for DER.

We emphasize first the value in the current practice of utilizing consistent system-wide demand scenarios developed by the CEC, which still allows for disaggregation across local subregions or planning areas. And second, the importance of utilizing multiple demand scenarios and sensitivity analyses to account for the range of probable trajectories in the evolution of demand. The IRP in particular should consider the already very large and rapidly accelerating growth in DER, and the ability of DER to influence both demand forecasts and the increasing flexibility of that demand—opportunities for load modification are among the largest of resource assets available, both as a dispatchable resource and to a greater degree as a resource that responds over time to rates, tariffs, and policy decisions.

(a) The Commission Should Coordinate this Proceeding with the IRP to Improve Consideration of DER.

DPP focuses on distribution infrastructure capacity, which addresses highly localized forecasts and is subject to different load shape and peak profiles than the IRP, which reflects regional needs largely measured at or above the distribution substation interface. The IRP model does not currently optimize with consideration of distribution resources and only considers net distribution load as an exogenous fixed IEPR input. This current IRP practice does not reflect reality. It is essential for the Commission to make this long overdue adjustment to the method utilized in the IRP, or at the very least recommend so in this proceeding, to include optimization of distributed resources.

(b) Different DPP Demand Scenarios Do Not Affect the GRC.

Variations in actual distribution expenditures are normal and assumed in the GRC, and are affected by many factors other than demand scenarios. As such, the use of different data sources and planning scenarios in DPP are likely to fall within the assumed margin of error in cost and revenue requirement forecasts. Additionally, variations in demand result in parallel changes in revenue which will offset changes in revenue requirements associated with demand without impacting rates. Finally, any under- or over-collection through rates is accounted for in future rate adjustments.

6. Is a five-year planning horizon sufficient for distribution grid planning?

No.

A five-year planning horizon is not sufficient for distribution grid planning, particularly to serve DAC and other ESJ communities.

Distribution loads are anticipated to grow substantially across all areas as California pursues building and transportation electrification over the next two or more decades. Moreover, as the Energy Division has clarified, this proceeding focuses on the *anticipation* of a high DER future. This objective involves ensuring that planning tools, processes and community engagement efforts are in place to facilitate rapid integration of DER as we achieve a high DER future, or, preparing the grid to accommodate what is expected to be a high DER future and capture as much value as possible from DER.

As noted in our prior comments throughout this proceeding, it is important for this planning process to include the identification and integration of ESJ community resident needs into expectations of future DER growth, so that the Commission can tailor and proactively plan for DER deployment strategies to effectively meet those needs rather than react. Otherwise, there is a likely and foreseeable risk that DAC needs will not be addressed in a high DER future, precluding our ability to meet California's SB 100 and other climate and equity targets. A five-year planning horizon may be insufficient to capture the potential of DER in DAC and other ESJ communities.

In addition as a practical matter, it would be costly and inefficient to install new conductors and other equipment with multi-decade service life based on a five-year load growth forecast and then have to repeat the work and replace the equipment in only ten or fifteen years as capacity meeting the five-year forecast is exhausted. Overall, a five-year time horizon may not align with state and federal policies—which are designed to meet long-term societal needs—and may lead to planning decisions that risk becoming obsolete and unable to meet the rapid adoption of DER, especially in DAC and other ESJ communities.

(a) If not, what is an appropriate planning horizon and why? Should the same planning horizon used for the IEPR demand forecast (min. 15 years) be used for DPP?

Yes, it would be generally appropriate to utilize the IEPR demand forecasts consistently for coordination of all planning activities, subject to disaggregation and refinement within each local distribution planning area.

Longer-term (>15 years) capacity planning horizons align with the need for longer-term efforts to achieve state climate and energy justice policy goals. To the extent that well founded forecasts are available with information that would influence prudent upgrade investment plans and decisions, forecast data beyond five years should not be ignored. Planning should incorporate the best available forecast data, and should consider the functional lifespan of investments. For example, if a line requires reconductoring with an equipment life of more than 40 years, it is not cost-effective to size the new line based on a 5-10 year forecast only to replace the line again in the next 5-10 years. If the marginal cost of installing a higher capacity line is lower than the risk of doing the work twice, the larger capacity should be installed. Equipment should be selected to meet future needs and standards consistent with its operational life.

(b) How should Utilities present and manage the risks of underbuilding and/or overbuilding under extended planning horizons?

Updating plans as additional data becomes available and incorporating longer term forecasts and planning horizons that maximize the value of DER mitigates risks for underbuilding and/or overbuilding.

Planning and execution are separate and distinct operations. Planning incorporates both long-term and short-term timeframes, and includes an assessment of the degree of certainty, which is refined as additional information becomes available over time. It is appropriate to aim to install equipment that is likely to fulfill the need it is serving for the foreseeable future, including the economic life of the equipment in order to avoid repeating the work. This reasonably addresses the risk of underbuilding.

By contrast, construction and installation are the execution of plans, which is generally scheduled only as needed to accommodate a forecasted deficiency in capacity or reliability before the date upon which that deficiency is likely to occur. This allows plans to be updated as that date approaches, and for schedules to be advanced or deferred as the need becomes clearer. This process of refinement reduces the risk of overbuilding.[36]

These approaches are consistent with existing distribution planning practices. In addition, we recommend formally incorporating longer term forecasts and planning horizons. Longer term planning not only reduces the risk of underbuilding but also allows time to develop staff recruitment and training, and establish future supply contracts in time to meet any expected surge in demand or potential bottlenecks in supply.

Leveraging DER in a manner that minimizes the need for more costly grid investments also minimizes the risk of overbuilding. Before making major capital improvements to the grid, utilities should first look to DER to provide whatever requirements that triggered the need. In this regard, it is important for the Commission to recognize potentially competing interests in a high-DER future. Because the utilities' rates of return are in large part tied to the value of capital assets deployed to serve load, there's a strong incentive for them to prioritize capital investments over consumer or third-party owned and controlled DER.[37] Maximizing large capital investments in the grid risks burdening ratepayers with the costs of overbuilding as significant

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[36] See e.g. CAISO News Release, Plan calls for canceling, modifying projects to avoid $2.6 billion in costs, (March 23, 2018) *available at* https://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf.

[37] *See e.g.* Center for Biological Diversity, Rooftop Solar Justice (2023) *available at* https://www.biologicaldiversity.org/programs/energy-justice/pdfs/Rooftop-Solar-Justice-Report-March-2023.pdf.

stranded investments raise rates for all customers, and could result in high fixed charges, or a departing load charge.

We recognize there are necessary investments to facilitate the transition to a high DER future and do not oppose such grid modernization expenditures. However, evaluating what constitutes a necessary grid modernization investment requires a deep understanding of both conventional grid engineering and planning expertise *and* an adequate consideration of the community benefits, grid benefits, and market trends for DER. Unless planning and investment decisions recognize the potential of DER as a grid asset, it will be difficult to find a balance between over- and under-investing in grid enhancements. Two issues that should center community needs and are to be considered in this proceeding—an independent DSO model and Performance Based Ratemaking—could alleviate this potential conflict between the utilities' financial imperatives and the desire to encourage the beneficial deployment of DER.

(c) How should the planned investments identified under a longer planning horizon be prioritized for investment?

The same prioritization and risk mitigation principles and practices used in the current five-year planning horizon are fully applicable for incorporating longer term planning; the main difference will be the use of additional data to inform these practices, including load growth and climate impact adaptation beyond five-years related to equipment performance and extreme weather factors.

In addition, prioritization for communities who have been underserved and cannot or have limited access to DERs because of lack of grid upgrades should be prioritized first for investments. If not, the same historical inequities in the energy system in California will transfer over to electrification and adoption of new technologies and leave communities behind while wealthier parts of the state will be able to access them regardless.

Transmission and Load Flexibility

7. **How should the scope and cost of transmission and sub-transmission upgrades be considered in utility DPP?**

Transmission and sub-transmission upgrades are integral to utility distribution planning. Virtually all load occurs within the distribution system. This load can be met or mitigated through load modification driven by tariffs, through DER (including energy efficiency, demand response and flexibility, generation and storage), and/or through (sub)transmission delivering energy from non-local resources. These three buckets of resources must be considered together to determine and pursue the appropriate balance and minimize both direct ratepayer costs and other indirect or externalized impacts, and developed in alignment with broader local and state priorities, including the recommendations in the Commission's ESJ Action Plan.

Specifically, the DPP must address local capacity needs that cannot be met through (sub)transmission, and should aim to accommodate local resources whenever and wherever these will likely enable demand to be met at lower net ratepayer cost for equal or greater reliability of service relative to transmission-based solutions.

In doing so, the Commission must assess the appropriate costs and benefits. For instance, a common critical error in efforts to determine "least cost and best fit" arises when the cost of energy is assessed at the wholesale price without consideration of the ultimate additional delivery costs for ratepayers of transmitting that energy. Transmission and delivery costs have long been the fastest rising component of ratepayer bills, which have increased far faster than general inflation even as the cost of energy has fallen to historic lows, driven by reductions in the cost of renewable generation.[38]

[38] *See supra*, note 33.

Finally, transmission planning necessarily considers the maximum potential need and proposes all the projects required to meet that need on ten and twenty-year horizons. While it is essential to develop these plans and related preparatory steps long ahead of any likely need, actual construction will not occur until years later, as forecasts are refined. Ratepayers realize very substantial savings whenever the need for future capacity can be canceled or deferred, which occurs with each CAISO Transmission Planning Process update.[39] These real savings apply both to planned projects and also to projects which will not be planned because future needs were either avoided or otherwise mitigated. The DPP improvements must address these real-world circumstances and integrate the most accurate assessment of avoided costs as possible.

8. Should the Grid Needs Assessment / Distribution Deferral Opportunity Reports (GNA/DDOR) filings account for secondary distribution infrastructure (e.g., service transformers) or additional primary distribution (e.g., feeder line segments) infrastructure needs? If so, how, and why? Would this result in avoided and/or deferred costs? If so, how?

Yes.

GNA and DDOR should seek to account for secondary distribution infrastructure needs and opportunities for distribution deferral. However, due to the higher degree of uncertainty and lower cost per upgrade, the approach to identifying needs and mitigations should be modified.

Most secondary upgrades will fall far below the cost threshold for DDOR and would be inappropriate for deferral service contracts, especially when considering that secondary facilities

[39] *Supra*, note 36 (which outlines the proposed design and construction of transmission networks for the next decade, and identified 17 new transmission projects at a combined cost of nearly $271.3 million. The plan also recommends the cancellation of 18 transmission projects and revisions of 21 other projects in Pacific Gas & Electric (PG&E) area and two in the San Diego Gas & Electric area, avoiding an estimated $2.6 billion in future costs. The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation.")

each typically serve only a handful of customers or a single building. Due to the extremely large number of secondary circuits and the difficulty of forecasting changing needs among such small individual sets of customers with any certainty, it would be far more challenging to try to identify individual projects for deferral. As an alternative, it is possible to assign a simplified probability (for example, high, medium, low) based on highly disaggregated and localized forecasts overlaid against known remaining capacity of each secondary section (such as being performed in the current Electrification Study by Kevala). Local engagement, if available and as detailed throughout this comment, can assist this task. Standardized optional tariffs or incentives targeted at reducing the need for upgrades could prove dramatically simpler to employ and administer, and result in significant cost savings. In this respect, GNA and DDOR should inform the development of tariffs in general to mitigate capital expenditures, and might also be employed at specific locations for a limited time.

Secondary distribution infrastructure represents a substantial portion of grid costs, and electrification goals may drive major increases in loads served and trigger upgrades at an accelerated pace on a very high percentage of secondary lines. These upgrades may be mitigated through utilization of customer sited equipment to manage loads and DER operational impacts. This includes the use of smart inverter functions and operationalization being developed in Track 3 of this proceeding, smart thermostats, load management controls, and bi-direction charging and discharging of customer sited storage including electric vehicle batteries, as well as localized demand flexibility pricing signals currently being developed in R.22-07-005.

Rate design works in concert with tariffs for grid services, contracts, and real time pricing signals to influence both the general load shapes of customers and the response of customers and their automated equipment to specific grid conditions. It should be the responsibility of each distribution system operator and planning process to utilize all existing distributed resources available to achieve the most cost-effective design and operation of the grid. In this respect, any capacity to modify load should be considered a distribution resource, and employed based on least cost. Importantly, these cost-effective analyses must incorporate all relevant non-energy benefits and (avoided) social costs of DER.

9. **How should load flexibility (dynamic rates and other flexible load management strategies) be addressed in utility DPPs and on what implementation timeline? Responses should consider the scope and status of the proceeding on Advance Demand Flexibility Through Electric Rates (Rulemaking (R.) 22-07-005).**

DPPs should incorporate forward looking forecasts of changes in customer adoption of tariffs and devices, and the resulting behavior-driven effects on load shapes for each Distribution Planning Area, substation and circuit.

DPPs rely foundationally upon disaggregated CEC load forecasts. These forecasts reflect the impact of existing rate tariffs in which customers are enrolled, as well as trends in the adoption of customer devices that influence both peak loads and load shapes, including energy efficiency upgrades, EV charging, and PV installation. Each IOU employs disaggregation methods specific to their systems and experience. While both the CEC forecasts and IOU disaggregation should incorporate expected turnover of customer enrollment in various rate tariffs, the design and availability of tariffs is a policy matter determined by the Commission, and as such requires information and direction from the Commission, which should itself be informed by the DPP, GNA, and DDOR data. For example, shifting customers to time of use ("TOU") rates is specifically intended to influence customer behavior, and these behavioral changes in demand profiles must be factored into distribution planning as well as other planning and procurement processes.

As discussed in response to the prior question on secondary grid facilities, changes in customer behavior and resulting load have impacts which flow directly up through the distribution system. Both the Demand Flexibility proceeding and the Smart Inverter Operationalization Working Group within this proceeding are focused on opportunities to mitigate stresses on energy supply and delivery capacity, and reduce overall costs for ratepayers. Adoption and customer utilization of these tariffs and associated equipment will occur over time and within margins of statistical probability. The value of these mitigations should influence the design of new tariffs and the pace of transition from outdated tariffs, and do so in line with the recently updated Rate Design Principles.[40]

More broadly, as shown in the recent National Renewable Energy Laboratory ("NREL") White Paper, an integrated grid planning ("IGP") framework extends bulk system integrated resource planning to distribution networks calling for more granular modeling and forecasting, deeper modeling of transmission and distribution system interactions, and improved modeling of uncertainty and risk. We agree with the White Paper's conclusions that:

> Utilities are moving toward an IGP framework to manage uncertainty in the size, location, and timing of future load growth, as well as to enable innovative and cost-effective solutions to address future capacity needs. The business-as-usual distribution planning alternative may not be fully prepared to make equitable least-cost and cost-causation assessments . . .
>
> IGP with decision support tools could be used to proactively assess how long-term distribution capacity costs would change with and without managed electric vehicle charging, DERs, and other load management options. IGP could also help entities undertaking DSP to equitably allocate DER or electric vehicle interconnection costs . . .
>
> Objective metrics and decision-making frameworks to weigh the importance of each planning criteria should be clearly defined to align corporate utility goals with external stakeholders and regulatory bodies. New holistic and technology-agnostic metrics or planning criteria (e.g., for hosting capacity, resilience, equity, energy justice, energy efficiency, and distribution resource adequacy) are needed that can be applied with confidence to utility investments and non-wires solutions. Ultimately, the industry would benefit from having a distribution planning guide that can serve as a reference and can describe best practices on conducting

[40] *See* D.23-04-040.

> distribution planning activities, without prescribing a "one-size fits all" approach to distribution planning, since distribution grids across country have significant differences in their structure and operations.[41]

Demand flexibility proposals currently under consideration are tied to market operations that require a significant degree of customer sophistication, and as a result are likely to have limited impact, although future demand flexibility tariffs utilizing a simplified and automated approach for residential customers may have much larger beneficial effects. Furthermore, planning studies such as the current Electrification Impact Study led by Kevala should include scenarios which optimize use of current tariffs, such as EV rates which encourage charging load outside of peak hours. Current TOU rates are the default assumption in part 1 of the Draft Kevala study, with a resultant peak predicted at 9pm driven largely by EV charging. Promotion of available EV rates would result in a substantial change in that load shape.

However, regardless of near-term developments in the Demand Flexibility proceeding, TOU tariff rate transitions and other factors associated with building and transportation electrification policies will have large and predictable effects which clearly should be incorporated into the DPPs. It is also important to distinguish between distribution planning and actual project implementation. The plans are critical in preparing to meet future needs, but the actual investment is more flexible and finely calibrated to meeting the needs on something closer to a "just in time" basis based on locally specific data on development and interconnection applications. Planning should also integrate additional factors, as recommended by NREL, including resilience, equity, energy justice, energy efficiency, and distribution resource

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[41] NREL, Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support (November 2022) at v-vii, *available at* https://www.nrel.gov/docs/fy23osti/83892.pdf

adequacy. Returning to the core premise of this comment, planning must determine how to meet *community* needs.

Data Portals and Integration Capacity Analysis (ICA) Improvements

10. How do registration requirements impact the accessibility of the data portals and what changes are needed to improve access?

Each IOU's interactive ICA map should be widely available to the public without the need to sign in or request access.

Currently, for PG&E's ICA map, it is necessary to create login credentials before beginning use. To use SDG&E's ICA map, a user needs to request access, which often requires multiple days of waiting before a response, and then create login credentials. Furthermore, this access is revoked after a certain period. SCE's interactive ICA map, on the other hand, provides immediate access without the need to register or create login credentials. Given the importance of this data to resource planning and investment decisions, each IOU's interactive ICA map should be widely available to the public without the need to sign in or request access.

Similarly, each of the IOU's interactive ICA maps should provide an easy way to download the ICA spatial data in multiple, commonly used formats (for instance, GEarth, geodatabases). So far, PG&E and SDG&E allow users to download just ICA geodatabases, but only after users create login credentials and/or request access, whereas SCE allows users to download KML, shapefile, XML and GeoJSON formats of ICA spatial data through its interactive ICA map.

Generation and Load ICA Data Utility and Calculations

11. Should the Commission evaluate the accuracy of the Generation ICA and Load ICA data?

Yes. Accurate data is essential to adequate planning and investment decisions. An Independent Evaluator should evaluate accuracy of Generation and Load ICA data.

At the Update Workshop for the ESJ Action Plan, held on February 3 and 4th , 2021, certain key themes emerged, including "more transparency of data and information."[42] Greater transparency would "[p]rovide stakeholder and CPUC staff with tools and resources to facilitate analysis of ESJ issues and impacts."[43] Consistent with standard practice in other Commission programs and activities,[44] an independent evaluator should also be required in this proceeding to evaluate the accuracy of Generation ICA and Load ICA data. This independent evaluator should have the necessary skills (for instance, familiarity with each of the three software platforms used by the three IOUs), and the organizational ability to maintain an ongoing evaluator role.

Independent evaluators should have access to sufficient information to determine the accuracy of data based on both: 1) what percentage of data points are inaccurate; and 2) the degree of inaccuracy of those identified data points.

These improvements are needed as soon as possible, and evaluation should be ongoing to respond to real-world changes that may differ from planning. In addition, data validation needs to be conducted on a feeder-by-feeder basis throughout each of the IOU-service territories, particularly given the importance of ICA in the interconnection process.

12. How do segments with ICA hosting capacity equal or close to 0 kilowatts (kW) affect project planning for DER Capacity Analysis data and project developers?

Inaccurate data creates an economic disadvantage to DER deployment.

Adequate development and deployment of DER should not be impaired by inaccurate data. As noted above, it is imperative for the Commission to authorize improvements that can

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[42] CPUC ESJ Action Plan Ver. 2 at 53.
[43] *Id.*
[44] *See e.g.* D.18-01-004, requiring energy efficiency independent evaluators to submit a semi-annual report on the overall third-party solicitation process for PG&E, Southern California Edison, San Diego Gas & Electric, and Southern California Gas Company.

enable the proactive comparison of the costs of grid upgrades with the avoided costs, in particular avoided transmission costs and other benefits of DER. Accurate load and generation data also presents an opportunity to tackle delays in interconnection and address potentially unnecessary transmission access charges. Published information on planned investments or reconfiguration that would increase hosting capacity should be made available to the public as soon as possible, in addition to supplement the data on current existing capacity.

13. Are there other alternatives to hosting capacity maps that can facilitate cost-effective siting of DERs on the electric grid?

Adequate community engagement and consideration of non-energy benefits and (avoided) social costs will facilitate siting of DER.

Additional information related to cost-effective siting of DER should not be seen as an alternative to hosting capacity maps, but as a supplement to the information provided in these maps. Such information may include areas pre-screened for permitting and CEQA compliance, areas where local resource needs and constraints exist, and areas of particular economic interest.

As detailed above, a Community Engagement Plan should also identify opportunities to verify forecasts of on-the-ground conditions. This should be conducted in coordination with local entities to determine community needs that DER can offer. Similarly, that engagement could identify NEBs and social costs. Refining cost-effective determinations and evaluation metrics to consider these factors would improve delivery of community benefits through energy solutions, as recommended by NREL and others. Certainly, absent adequate consideration of these factors, certain projects may not "pencil out" under the current and deficient cost-effectiveness framework. As the CEC details in the 2022 IEPR update:

> Tribes and communities are best situated to determine their needs and wants. Tribes and communities are interested in energy and nonenergy benefits from . . . policies such as energy resiliency, reliable and affordable energy sources, lower utility bills, quality jobs, clean energy infrastructure, and more . . .

> Incorporating nonenergy benefits may produce greater benefits to all Californians by increasing the societal benefits produced by public funds. Incorporating and tracking these benefits supports investments essential to California's transition to a clean energy economy.[45]

Responses to Generation ICA and Load ICA Questions (14, 15, 16, and 17)

A Community Engagement Plan would assist in the determination of community needs, and Generation ICA or Load ICA data must be sufficiently accurate to realize those community needs with an adequate consideration of relevant DER projects. This includes meeting locally established targets and goals for EVs and building electrification. For instance, Los Angeles County is currently finalizing its Climate Action Plan that projects decarbonizing freight and otherwise prioritizing DER, including "in wildfire-prone communities [which] will provide an alternative to the costly infrastructure upgrades that would be required to maintain uninterrupted power service."[46] This is similarly important in DAC and other ESJ communities, where DER can play a key role in simultaneously solving grid constraints *and* building wealth in communities.

"Historically disadvantaged communities often have more inefficient buildings and less access to clean energy technology. This means that the higher energy load from buildings in disinvested neighborhoods can stress the local grid more than other areas, likely leading to a higher instance of grid constraints in underserved communities."[47] "Grid limits exacerbate existing inequities: households in increasingly Black-identifying and disadvantaged census block

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[45] *See e.g.* 2022 IEPR Update at A-9, available at https://www.energy.ca.gov/sites/default/files/2023-02/Adopted_2022_IEPR_Update_with_errata_ada.pdf.

[46] Los Angeles County, Revised Draft Climate Action Plan (2023) *available at* https://planning.lacounty.gov/wp-content/uploads/2023/03/LA-County-2045-CAP_PRDraft_Redline_Compare_Full.pdf.

[47] Institute for Market Transformation, Redistributing Power to Communities in Oregon (April 18, 2023) *available at* https://www.imt.org/news/redistributing-power-to-communities-in-oregon/

groups have disproportionately less access to new solar photovoltaic capacity based on circuit hosting capacity."[48]

Consequently, the Commission should prioritize the accuracy of Generation ICA and Load ICA data in DAC and other ESJ communities. In order to maximize community benefits that DER can offer, however, as detailed above, the Commission must also include these benefits in its analyses and ensure that the estimates of avoided costs of traditional grid solutions reflect actual avoided investment so that cost-effective determinations are not skewed towards major, expensive, and unnecessary grid infrastructure upgrades.

18. Should load flexibility be incorporated in Load ICA results and maps? If so, then how?

ICA methodology is inherently retrospective based on the past 1-3 years of line data. As such, any effects of load flexibility being utilized, and its impact on ICA results, will already automatically be captured by existing ICA methodology and reflected in each results update. Full updates of results are performed annually, and updates are performed monthly wherever interconnection or configuration changes are recorded.

However, there is a valuable opportunity to additionally provide prospective forecasts of future ICA results that will show the forward-looking impacts of planned or expected actions including utility grid upgrades, and rates or policies adopted by the state and Commission that will change customer behavior. This work should already be performed in each IOUs' DPP, which relies upon forecasts from the CEC and their internal disaggregation methods to develop their annual Grid Needs Assessment. The results of this work could relatively easily be

[48] *Id.*; *see also* Brockway, Anna M; Conde, Jennifer; Callaway, Duncan, Inequitable access to distributed energy resources due to grid infrastructure limits in California (2021), *available at* https://escholarship.org/uc/item/6pc2k2tv.

published in concert with the ICA results and maps to indicated expected changes in those results which would reflect planned investments and effects of expected changes in (net) load.

Understanding where and when grid capacity is expected to change is useful both for planning utility grid investments and modernization in line with a high DER future, and crucially also for communities and customers reliant upon this information to evaluate the feasibility and timing of their projects. For example, a local community project may not be possible without a substation upgrade. Requesting the upgrade where one was not planned will likely take at least five years and may incur costs that would make the project not financially feasible. However, if an upgrade need had already been identified and planned, the capacity may be available much sooner and not trigger dedicated cost responsibility allocation against the project. This is vital information to local community planners.

DPP Alignment with Transportation Electrification

(Responses to Questions 19, 20, and 21)

As described above, utilities should pursue community engagement so that EV and EVSE siting decisions are made in consultation with local communities and local community-based organizations. Statewide EVSE buildout (e.g. going from roughly 80,000 chargers today to over a million by end of the decade) will necessarily require extensive community engagement because local authorities have jurisdictional control over public locations where EVSE will need to be installed; local communities will have input regarding EVSE siting commensurate with local priorities. California local governments may not have sufficient capacity to engage in climate mitigation and adaptation planning.[49] These capacity limitations also apply to EV and

[49] *See* Ounce of Prevention, Advancing Equitable Climate Resilience Planning in California status report on implementation of Senate Bill 379 (2015) *available at* https://www.climateresolve.org/wp-content/uploads/2023/04/Ounce-of-Prevention-3.28.pdf

EVSE planning, underscoring the importance of the recommendation above to provide funding to local communities to support planning.[50]

In so doing, the utilities should also integrate funding decisions (for example, from the CEC and other state agency programs that fund and site EVSEs) into their distribution planning. Utilities should not assume that EVSE installations will require proportionate distribution upgrades, as increases in EVs will not necessarily result in increases in peak load, for the reasons detailed below.

Local EV and EVSE planning should consider not only load growth associated with increased EV market penetration and needed distribution upgrades, but also the extent to which increased EV market penetration could provide benefits including enhanced grid reliability and resilience.

Importantly, while utilities should plan for EV load on the grid, they should also anticipate local storage opportunities from EV adoption. Local governments own thousands of vehicles. They could be planning to not only electrify their fleets, but also to use the battery storage available in these vehicles when the power goes out. Some local governments have already begun to use EVs as grid assets; in a partnership between Alameda Contra Costa Transit and Schneider Electric,[51] bidirectional electric buses will be deployed to the West Oakland public library to power air filtration and air conditioning for Oakland residents during heatwaves

[50] *See* Ounce of Prevention, Advancing Equitable Climate Resilience Planning in California status report on implementation of Senate Bill 379 (2015) *available at* https://www.climateresolve.org/wp-content/uploads/2023/04/Ounce-of-Prevention-3.28.pdf

[51] See Microgrid Knowledge, Schneider and partners to pilot unusual EV microgrid in Oakland, California (October 2022) *available at* https://www.microgridknowledge.com/editors-choice/article/11436854/schneider-and-partners-to-pilot-unusual-ev-microgrid-in-oakland-california

and blackouts. The Cajon Valley Union School district in Southern California is already using eight bidirectional buses to feed power to the grid during peak demand.[52]

Senator Nancy Skinner's bidirectional EV legislation, SB 233, would require EVs sold in California to have bidirectional capability by model year 2030.[53] Assuming 8 million EVs on the road in California with an export capacity of 10 kW per vehicle, EVs could potentially supply 80 GW of capacity; even a tiny fraction of California's EV fleet with bidirectional capability could provide an enormous demand flexibility resource for California, which becomes increasingly achievable as virtual power plants proliferate.[54] As Governor Newsom noted in December,[55] vehicle to grid integration ("VGI") presents a significant opportunity for California to provide global leadership in maximizing the benefits of clean energy.[56] According to analysis from the Electric Power Research Institute, VGI could provide $1B in annual grid cost savings benefits to California.[57] The Commission should ensure that DPP refinements can realize this potential.

DIDF Reform

"Known Loads"

22. Which of the following items should be included and tracked year over year via the Utilities' annual GNA/DDOR filings?

a. Comparison of Utilities' known loads to the IEPR demand forecast.

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52 See LA Times, How eight school buses are helping during power shortages: They're transporting electrons (July 2022) *available at* https://www.latimes.com/business/story/2022-07-27/electric-school-buses-in-el-cajon-will-send-power-to-the-grid

53 SB 233(Skinner), Introduced January 2023, *available at* https://legiscan.com/CA/text/SB233/2023

54 Brattle Group, Real Reliability: The Value of Virtual Power, *available at* https://www.brattle.com/real-reliability/

55 Governor December 2022 Address, *available at* https://www.youtube.com/watch?v=7ZGKh6dOvLY

56 *See also* Alaska Microgrid Group, California Legislation on Electric Vehicles Could Be a Global Game Changer *available at* https://www.alaskamicrogrid.org/post/california-legislation-on-electric-vehicles-could-be-a-global-game-changer

57 EPRI, Open Standards-Based Vehicle-to-Grid: Value Assessment (June 2019), *available at* https://www.epri.com/research/products/000000003002014771

b. **Known loads by customer type (commercial, residential, industrial) and customer load category (Building Load, Agricultural Pumps, Cultivation, EV load, etc.)**
c. **Standardized reporting format across Utilities.**
d. **Any other recommended improvements identified in the IPE 2023 Post-DPAG Report.**

The 2022 and 2023 IPE Post-DPAG Report and June 16, 2022 Ruling on reforms to the DIDF process made strides towards level setting the methods IOUs use when including known loads in their Grid Needs Assessment, as well as including Known Load reports as part of the standard, annual DIDF. The June 16, 2022 Ruling required IOUs: (i) to "include a spreadsheet listing of all Known Load Projects with their 2022 GNA/DDOR filing;" (ii) to "report data sufficient to track, over time, whether specific known load projects materialize;" (iii) to "include a unique project identifier, impacted circuit, initial service request date, load amount, current expected in-service date or indication if service request was cancelled, if appropriate, and type/category of load and, if appropriate, the actual date service was initially provided and the amount;" (iv) to "indicate whether each project was classified as an incremental or embedded known load project as defined by SCE"; and in their GNA/DDOR filings (v) to "include a detailed review of known load projects in their GNA/DDOR filings, including but not limited to, types of loads, number, amounts, and timing [and a] summary . . . similar to the evaluation provided in Section 3 of the March 17, 2022 IPE Report"; (vi) to "evaluate in their 2022 GNA/DDOR filings SCE's approach to tracking known load projects that identifies embedded and incremental loads and compare it to the PG&E and SDG&E approaches with the goal of proposing a standardized approach in the IOUs' 2023 DIDF reform comments."

23. Considering the misalignment between the IEPR demand forecast and "known load" projects as identified in the Independent Professional Engineer (IPE) DPAG and Post-DPAG reports and the Kevala DIDF report:

How should Utilities investigate and manage the risks of underbuilding and/or overbuilding caused by this misalignment? Does this increase the risk of missing DER deferral opportunities? If so, how should it be resolved?

See response to Question 6(b).

Potential Pause of the Focus on Reviewing Deferral Opportunity Selection

24. Given the proceeding schedule and scope of issues for Track 1, Phase 1, what changes could be made to the DIDF process, starting in 2023, to free up stakeholder time for broader DPP reform discussions? For example, should the focus on deferral opportunity identification, selection, and review via the DPAG (roughly August 15th to November 15th) be paused during the 2024 and 2025 DIDF cycles to allow time for alternate stakeholder workshops?

No response in opening comments.

Resiliency Grid Service

25. Should the definition of resiliency microgrid services be clarified via the DIDF Reform process to include other resiliency services?

Yes. The existing definition conflates resiliency and microgrid services.

The definition currently reads, "Resiliency (microgrid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."[58] The existing definition, however, conflates resiliency and microgrid services. While there can certainly be overlap between these, they are not the same – resiliency services can be offered without a microgrid, and microgrids can offer additional services beyond resiliency or absent resiliency.

Defining the service as providing "fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations" is overly narrow and incomplete. IEEE more broadly incorporates five aspects of resiliency: Prevention, Protection,

[58] D.16-12-036 at 8

Mitigation, Response, and Recovery. This means that resiliency services: 1. Prevent disruption events; 2. Resist disruption of service when an event occurs; 3. Reduce the magnitude and breadth of disruption when it can't be avoided; and 4. Accelerate recovery, reducing the duration of disruption.

While the service performed is electrical in nature, resiliency is important due to the *customer and community* services which are dependent upon electricity, and as a result these cannot be measured simply in electrical terms, and should instead be understood in terms of impacts on customers, including access to critical services such as water, heating and cooling, communication, transportation, and critical public facilities, and the resulting social burden that is avoided.

The Resiliency & Microgrids Working Group in R.19-09-009 noted the distinction between reliability and resilience put forth by Sandia National Laboratory as "Reliability measures impacts to the system; Resilience measures impacts to humans." However, various definitions of resilience have been adopted by different agencies. As indicated by the IEEE approach, resilience is focused on the ability to respond to an event and either avoid an outage, or at least limit the scope and duration of an outage and its impacts on dependent services and populations.

As established in D.16-12-036, the definition also distinguishes between "load-modifying" and "supply side" services. However, during abnormal grid configurations this distinction can change. Importantly, the distinction between "load-modifying" and "supply side" is not easily and consistently applicable to microgrids.

Microgrids can be configured at a wide range of scales, may be established entirely behind a customer meter, may serve a campus grid that connects to the utility grid at one or more points, or may be established incorporating portions of the utility grid to serve all or part of a community. Each of these configurations ordinarily operate in parallel with the utility grid, but are capable of being "islanded" and operating independently, potentially incorporating portions of the utility grid. As such, the resources comprising the microgrid may be considered "load-modifying" in normal grid configuration, but considered to be "supply side" in abnormal (grid outage) configurations. This is clearly demonstrated in the Redwood Coast Airport Microgrid which is not utility owned but is designed to serve airport load and energy markets under normal conditions, and to serve neighboring PG&E customers only during a grid outage. In contrast, SDG&E's Borrego Springs microgrid is utility owned and operated with "supply side" resources, but incorporates and utilizes customer owned resources, especially during islanded operations. Consequently, the Commission must revise the definition of "resiliency services." Revision should occur with input from both Resiliency & Microgrids Working Group and parties in this proceeding, and it would be premature to propose specific revision language at this time.

Partnership Pilot and RFO

> **26. To date, no contracts have been signed for a Partnership Pilot procurement. However, for the 2021/2022 DIDF Cycle, PG&E awarded two deferral contracts via the RFO solicitation process for behind-the-meter projects.**
>
> **a. What improvements can be made to the Partnership Pilot to increase the number of deferral contracts awarded?**
>
> *Community and local engagement should assist partnership pilot selection, especially in DAC and other ESJ communities. Selection and evaluation criteria should also be based on community needs.*

Resources that are capable of providing deferral services are also capable of providing energy and other services. Restricting contracts to a single service, however, greatly limits the use of these resources, and subsequent interest in participation. We strongly recommend accepting all cost-effective services and energy offered by a bidder in order to stimulate interest.

Currently, prescreened aggregators in limited geographic locations are eligible to apply for partnership pilot projects. We are not aware whether these prescreened aggregators focus on DAC or other ESJ communities, but recommend that the reach of solicitation be broadened to ensure such focus. A Community Engagement Plan that spans Tracks 1 and 2 of this proceeding could provide recommendations on how to make such outreach effective.

As detailed above and in our prior comments, cost-effective determinations are skewed against DER and in favor of underestimated avoided costs of transmission and other related grid improvements. The Commission must remedy this issue and work in concert with the CEC to develop the full range of local, environmental and economic benefits that DER can deliver. The Commission should then integrate these benefits into its cost-effective determinations, whether at the pilot selection or evaluation phase. For instance, PG&E currently evaluates projects based on whether DER is cost-effective compared to the planned investment. This cost-effective determination, however, should also incorporate NEBs and other community needs that DER can meet. Similarly, the Commission must also ensure the consideration of accurate avoided costs of planned investment.

Meeting community needs should instead be a central criteria to award and evaluate partnership pilot contracts. Certainly, some prescreened aggregators may be limited by certain projects not "penciling out" under current insufficient cost-effectiveness determinations and evaluations.

b. To what extent does bidder certainty challenge Partnership Pilot success, and how can bidder certainty be increased for the Pilot?

The process of developing bids is inherently a time-consuming and significant financial risk for any bidder. This uncertain investment of time and resources discourages participation and raises the price of bids to cover the cost and risk. If the likelihood of being awarded a contract following a submission of a bid is 20%, the bidder must generally multiply that cost five times in order to break even. For this reason, offering a clear opportunity without the uncertainty should both increase the interest and participation, and allow uptake at a lower cost that would be necessary for an uncertain bid. The partnership pilot has made some strides in simplifying the process, and allowing offers that partially meet needs, but can go further through offering clear opportunities to provide services at a defined cost-effective rate, with an emphasis on utilizing existing local resources, and minimizing the need to commit additional capital investment.

Finally, community buy-in for DER is an influential factor in pilot success. Adequate community and local engagement will not only "popularize" DER but also subsequently increase a pilot's feasibility where aggregators may have a larger pool of potential DER participants. This is critical for a high DER future.

VI. Conclusion

For the foregoing reasons, we respectfully request that the Commission adopt a Community Engagement Plan for Tracks 1 and 2 of this proceeding, and refine the DPP to include the recommendations detailed in this comment.

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Respectfully submitted,

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