BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CLEAN COALITION COMMENTS IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S RULING DIRECTING RESPONSES TO QUESTIONS ON TRACK 1 PHASE 1

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I. INTRODUCTION

Pursuant to Rule 6.2 of the Rules of Practice and procedure of the California Public Utilities Commission ("the Commission"), the Clean Coalition respectfully submits these opening comments in response to the *Administrative Law Judge's* ("ALJ") *Ruling Directing Responses to Questions On Track 1 Phase 1*, issued at the Commission on April 6, 2023.

We appreciate the opportunity to discuss the distribution planning process ("DPP"), an issue that is at the center of numerous related issues, including electrification, resilience, interconnection, energizations, integration of distributed energy resources ("DER"), and how the grid of the future will function - via an increasingly bi-directional flow of energy. It will be important to consider each of these issues and how they intersect with the distribution grid when considering how to reform the DPP. Addressing distribution planning in isolation cannot produce meaningful solutions and will only serve to perpetuate existing concerns about policy/regulatory conversations occurring in a silo. The DPP not only has implications for the state's energy future; it will also be critical for the deployment of new—and affordable—housing stock, necessitating a greater role for communities and local governments in the planning process. While the existing DPP contains a local component (based on known loads and projected load growth), like the rest of electrical system planning, it mainly occurs through a top-down undertaking that focuses on system-wide reliability and is designed to meet demand during peak periods. To truly meet the state's ambition climate goals and address historical inequities, the process needs to evolve so community needs, and equity concerns, are central considerations.

The existing DPP—which includes a system level forecast from the California Energy Commission's ("CEC") Integrated Energy Policy Report ("IEPR") that is disaggregated into a Grid Needs Assessment ("GNA") and a Distribution Deferral Opportunities Report ("DDOR")—

is the cumulation of more than five years of work and has led to a functional grid capable of meeting the basic requirements of a monopolized utility (safe and reliable service). Yet, if the past five years have proven anything, it is that climate change and California's legislatively mandated energy goals are creating an evolving set of conditions that the grid must be able to handle. The multitude of existing challenges that have been exposed recently[1] will be exacerbated and have the potential to become significant roadblocks in the clean energy transition if not addressed immediately. Therefore, the distribution grid and our planning processes must be capable of adapting, through the deployment proactive solutions, wherever possible and should endow the utilities with the flexibility required to meet unique location-specific ratepayer needs without being overly constrained by the need to avoid cost shifts.[2] However, it is also important that solutions are increasingly community-driven and that a key aspect of the planning process is building in a mechanism to enable two-way conversations between the utilities and stakeholders, namely local governments, businesses, and residents. Greater data sharing and transparency in the planning process will result in more accurate distribution planning, which is essential since load growth occurs locally.

When it comes to the bulk power system, the CEC (via the IEPR), the CPUC (via the IRP[3]), and CAISO (via the TPP[4]) actively select the energy resource portfolio and new transmission infrastructure that will be necessary to ensure system reliability. Public Safety Power Shutoffs ("PSPS") and extreme weather events in 2019, 2020, and 2022 all resulted in significant changes to procurement orders and requirements for increased amounts of new transmission infrastructure. The missing piece of the puzzle has been considering changes to the distribution grid and role of DER, especially regarding the value created through reducing peak transmission usage and the improved efficiency that comes from meeting loads locally.

Under the Proposed Scenario in the 2022 Scoping Plan, the California Air Resources Board ("CARB") noted that load growth is expected to rise by 68% by 2045.[5] While the increased demand will be distributed throughout the electrical grid to an extent, it will primarily

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[1] These challenges include long timelines for interconnection and energizations, high costs for distribution upgrades, and a lack of planning for resilience, to name a few.
[2] The Clean Coalition believes that avoiding cost shifts is important and that accurate cost causation remains a necessity, but if our regulation does not allow the flexibility to deploy desired solutions (while allocating costs properly), it will be difficult to fully achieve our climate goals.
[3] Integrated Resources Plan, which is drafted in the CPUC proceeding R. 20-05-003.
[4] Transmission Planning Process is released annually by the California Independent System Operator.
[5] https://ww2.arb.ca.gov/resources/fact-sheets/californias-2022-climate-change-scoping-plan-fact-sheet

occur on a local level, as both transportation and building electrification will take place on the distribution grid. This necessitates a significant conversation about how to amend the existing distribution planning processes to handle the influx of DER. Consider the example of transportation electrification. Through the first quarter of 2023, California has 1.5 million electric vehicles ("EVs") on the road, already achieving 30% of former Governor Jerry Brown's goal of 5 million EVs by 2030.[6] Fully achieving that goal could increase the total electric load by around 10%[7], a number that does not account for Governor Newsom's Executive Order banning the sale of gasoline-powered vehicles by 2035[8] or full transportation electrification. The same study found, "that across PG&E's service territory, 443 circuits will require upgrades (nearly 20% of all circuits) and merely 88 of these feeders have planned upgrades in the future."[9] The distribution grid should grow in parallel with local loads, albeit the planning process should also lay out the pathway of distribution upgrades and expansion that will be required to make the full transition a reality, which will necessitate conversations about the future of the distribution grid and how to implement a longer planning horizon.

Besides increased demand for electricity due to electrification, it is imperative to consider how the distribution grid will operate in the future and whether distribution-level markets will be available when considering distribution planning. The Clean Coalition believes that transitioning to Distribution System Operator ("DSO"), which is being discussed in Track 2 of this proceeding, is necessary to enable a grid of the future that is both resilient and reliable. A White paper has been released as a preliminary introduction to the concept of a DSO, but the full discussion about a DSO and its role has not yet begun. Regardless, it is important that the any debate about the future of the DPP does not occur in a silo; it should occur alongside conversations about how the grid is operated in the future. Together, the two subjects represent a broader picture and will enable the transition to a decarbonized/electrified future desired by policymakers and citizens. A DSO will help integrate longer-term distribution planning with DER integration and grid modernization, unlocking the full value of DER, the potential of

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[6] https://www.latimes.com/california/story/2023-04-25/california-hits-1-5-million-in-zero-emission-vehicle-sales#:~:text=Jerry%20Brown%20in%202018%20set,powered%20passenger%20cars%20by%202035.

[7] Alan Jenn, Jake Highleyman, Distribution grid impacts of electric vehicles: A California case study, iScience, Volume 25, Issue 1, 2022, 103686, ISSN 2589-0042, https://doi.org/10.1016/j.isci.2021.103686.

[8] https://www.gov.ca.gov/2020/09/23/governor-newsom-announces-california-will-phase-out-gasoline-powered-cars-drastically-reduce-demand-for-fossil-fuel-in-californias-fight-against-climate-change/

[9] Alan Jenn, Jake Highleyman, Distribution grid impacts of electric vehicles: A California case study, iScience, Volume 25, Issue 1, 2022, 103686, ISSN 2589-0042, https://doi.org/10.1016/j.isci.2021.103686.

demand flexibility, and the widespread deployment of cost-effective Community Microgrids In the case of distribution planning and a DSO, while the status quo is a functional grid, it is does not necessarily mean that the status quo should persist without a detailed examination of efficiency/effectiveness as compared to other well-thought-out alternatives..

II. DESCRIPTION OF PARTY

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER") — such as local renewables, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

III. Responses to Questions

Local Planning Engagement

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 include a mechanism that enables two-way conversations between utilities and local governments, or entities with a significant load. Infrastructure buildouts, whether they are related to new housing, economic development, or the energy system will not be successful if planned in a silo. Each year, utilities should discuss conditions on the local distribution grid and existing constraints (as well as planned upgrades) with community leaders to ensure that there are no surprises that inhibit development plans. For example, municipalities designing local housing plans should involve the local electric utility company to ensure that the existing distribution grid will be able to handle new Title 24 compliant housing, or that the grid will be upgraded in time to match the construction schedule. Municipalities should have the opportunity to discuss locations where targeted deployments of DER could be beneficial to the ratepayers, especially to meet local capacity requirements ("LCR") or speed up the retirement of fossil fuel assets. Though procuring resources for LCR and broader Resource Adequacy is the responsibility of the incumbent Load Serving Entity ("LSE") or utility, local governments should have the opportunity to be an informed participant, which will ideally improve the resource siting process and maximize the benefits to residents. In addition to conversations about local development and reliability, distribution grid planning and resource siting inherently factor into community resilience considerations. The DPP should include opportunities for local governments to plan options for short- and long-term resilience, starting by identifying critical community facilities and moving towards discussions about deploying broader resilience solutions including microgrids. While DER are much smaller than the typical utility-scale project, each deployment of distributed generation helps to set the stage for the deployment of a Community Microgrid. For example, the Goleta Load Pocket ("GLP"), which spans 70 miles of coastline, from Point Conception to Lake Casitas, encompassing the cities of Goleta, Santa Barbara, and Carpinteria, has a connection to the transmission system that is routed through the heart of fire, landslide, and earthquake zones via the Goleta Substation, making it the perfect location to site a Community Microgrid.

Map of the Goleta Load Pocket

The Clean Coalition has worked to size such a Community Microgrid that would be capable of sustaining the most critical loads in the region for an extended period in the GLP. We found that achieving indefinite renewables-driven backup power that provides 100% protection to the GLP against a complete transmission outage (known as an "N-2 event") will require 200 MW of solar and 400 MWh of energy storage to be sited within the GLP. Much of the energy storage has already been deployed; what the GLP needs most to advance the GLP Community

Microgrid is more deployed local solar and the right set of circumstances (e.g., discussions with local governments and a utility willing to work as a partner).

There are two other types of engagement that are necessary to improve the DPP. The first is related to the number of utility staff that are available in each area of the utility's service territory. Local planners are the boots on the ground, making them the most immediate link between local communities and the utility. They are key to ensuring that interconnection applications can be submitted in a timely fashion and are necessary to conduct site visits. Communities should be able to discuss the number of local planners with the utility and request more if the pace of development is being slowed. Moreover, as the Center for Biological Diversity explained in public comments in a recent workshop, ensuring that DACs are staffed by an increased number of Local Planners—which will be necessary to increase the historically slow rate of DER deployment and make the transition to electrification— should be considered an equity measure.

Second, municipalities should have an open line of communication with the utilities to discuss community-specific solutions and how to avoid cost shifts while deploying those solutions. In proceedings across the CPUC, such as the microgrids proceeding, the debate has been limited because of statutory requirements to avoid cost shifts. This is not to say that the Clean Coalition is in favor of cost shifts, it is lamenting the fact that cost shifts can be a conversation stopper, even when discussing real energy needs. We are in favor of ratepayers paying their fair share of costs and are not proponents of cost shifts, but we also understand that there are solutions that will benefit ratepayers without benefiting the utility's entire rate base. To continue with the example of resilience from above, the benefits of a Community Microgrid accrue to any ratepayer who is within the footprint of the microgrid. Moreover, an initial deployment of a Community Microgrid can be expanded to include a greater number of ratepayers over time, in addition to other critical community facilities. Communities should have the right to take resilience into their own hands and deploy Community Microgrids without being hindered by a cost shift. Therefore, it is worth adding a mechanism to the DPP so that rates for a specific area can be increased to pay for a unique solution like a Community Microgrid without also increasing rates for everyone in the utility service territory (and causing a cost shift). While this could be achieved via a tariff, such a tariff does not currently exist and is not yet being considered. See the Clean Coalition's Resilient Energy Subscription ("RES"), which is a straightforward market mechanism that allows any facility within the footprint of a Community Microgrid to pay a simple fee on top of its normal electricity tariff for a guaranteed daily delivery of locally generated renewable energy during grid outages, ensuring unparalleled energy resilience.[10] Since the DPP considers resilience needs, we believe it is appropriate for the Commission to consider a mechanism to more narrowly allocate costs than to the entire rate base.

2. *Energy Division's 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work,1 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 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?*

No comment.

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

Disadvantaged Communities ("DACs") are going to need significant investment to achieve equity and environmental justice goals. Due to great levels of historical DER deployment, the distribution grids in communities located in higher socioeconomic areas have usually been upgraded more than the distribution grids in DACs. Therefore, in addition to the funds available to help subsidize the cost of electric vehicles ("EVs"), distributed generation, and other electrification measures, it will be necessary to consider what amount of investment will be necessary to ensure that DACs will have distribution grids capable of handling the transition to electrification, rather than taking a piecemeal approach that will undoubtedly result in significant delays for upgrades. This type of approach is forward looking and proactively considers the infrastructure that will be necessary to achieve full decarbonization/electrification, whereas the existing process does not inherently treat DACs and non-DACs, though historical income is used as a predictive factor when considering the possibility of DER adoption.[11]

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[10] https://clean-coalition.org/news/webinar-resilient-energy-subscription-res-a-streamlined-market-based-approach-to-financing-community-microgrids-wednesday-31-august-2022/

[11] SDG&E Response to DPAG Questions on October 6, 2022. "The methodology proposed by SDG&E to select the CDOs that will be offered for deferral through Standard Offer Contract pilot and Partnership Pilot, *is based on the assumption that the average income of people served by a particular distribution circuit is a factor indicating the potential to expand DER capacity to defer a planned distribution upgrade on the circuit.* This assumption has not been validated through any statistical analysis and SDG&E welcomes suggestions for alternative approaches."

Local community engagement is also imperative to help communities understand where EV chargers might be sited, for public charging banks as well as fleet electrification purposes. Communities need to know which locations will necessitate distribution upgrades, whether upgrade costs can be shared (rather than shouldering a single project with the full cost burden of the upgrade), and if a microgrid or other solution might limit the need for upgrades. Broad information about the impacts of residential EV charging will be needed to help communities understand the scope of main panel and secondary distribution upgrades that could be required as the entire community electrifies. There has been a recent influx of issues related to interconnection and new energizations that have come to light (in Humboldt County, Fresno, and other locations) demonstrating that the existing processes are not as effective as once thought. If changes are not made to the process now, the existing challenges will be exacerbated into major roadblocks to achieving electrification, which cannot happen. Change to the existing process and community engagement that considers proactive solutions will be necessary to ensure that the transition can occur unincumbered.

Finally, as can be seen in the Commission's ESJ Action Plan, ensuring resilience for DACs is a key goal which can only be achieved through local community engagement. Effective resilience planning will require community engagement to determine what facilities and which loads are most critical for sustaining a functional community. To maximize the resilience benefits of Community Microgrids and the potential value of demand flexibility, load tiering on a distribution level will be essential, a role that the utility is best posed to serve.

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? If yes,*

Yes, in part because the planning horizon should show the path required to achieve the state's energy goals. The demand forecasts should consider the rate of deployment that will be necessary and ensure that the distribution grid will be upgraded proactively to enable such an unprecedented buildout. The DPP should also consider a scenario based on a High Social Cost of Carbon, which is being discussed in the DER programs proceeding (R. 22-11-013). Forecasts modeling high levels of EV adoption should also be considered.

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

No comment.

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

The IEPR forecast is a useful top-down demand scenario that should be supplemented with a bottom-up forecast that improves the accuracy of the existing methods that the utilities use to disaggregate the IEPR forecast to consider local constraints. All known load, projects in the interconnection queue, EV adoption rates, and expected year-over-year increases in DER adoption rates should be considered. In addition, economic development forecasts, fleet electrification, resilience plans, and Strategic Energy Plans should be used in local forecasts when available.

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

The existing IRP proceeding selects resource portfolios that include the least cost generation, which results in a portfolio of transmission-interconnected resources. However, these portfolios do not necessarily translate to the least cost for the ratepayers. Currently, the cost of delivering energy to the end user is greater than the cost of generating the energy itself. Including different demand scenarios and considering the total benefits and costs (of both generation and delivery) rather than just focusing on generation costs, will result in the selection of distributed solutions and reduced costs for new transmission infrastructure, ensuring the greatest amount of savings for the ratepayers. The proximity of a resource to the load being served matters, making distributed generation the most efficient way to serve loads as overall demand increases (driven by local load growth).

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

The Clean Coalition strongly believes that the DPP should have a longer planning horizon that is longer than five years to best align with the state's energy goals. Planning in five-year increments is not sufficient to ensure that the grid will be able to handle the influx of DER required to fully electrify and could create the false appearance that there are no immediate grid concerns in the short term when there are significant problems looming on the horizon, six or seven years away. The CAISO has considered this very issue due to the long lead time required to deploy transmission infrastructure and releases 10-year transmission plans on an annual basis.

In 2021, CAISO also released a 20-year transmission outlook for the first time to better express the total cost of achieving the state's climate goals. The Clean Coalition supports a similar structure for the DPP, given the pivotal role that distribution infrastructure will play in enabling electrification. We recommend that every five years the DPP forecast include a 20-year outlook in addition to a 10-year outlook that is revised annually. Given the volatility of distribution planning and predicting load growth, we would also support a 15-year planning horizon that is published every five years. An extended distribution planning horizon is necessary to effectively evaluate and harmonize with grid modernization and DER integration plans. For example, while the widespread deployment of Community Microgrids has not been achieved at the present time, resilience planning and setting the stage for Community Microgrid deployments down the road is quite attainable and will lead to significant ratepayer savings over time.

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?*

See the answer above.

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

See the answer above.

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

See the answer above.

Transmission and Load Flexibility

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

As mentioned above, planning for the grid and resource portfolio of the future should be holistic, in that it should consider both the cost of generation and the cost of delivering energy to the end-user. Any approved solutions should provide the greatest benefits to the ratepayers over the lifetime of the assets, rather than simply the least cost solution at the time it is deployed. Operations and maintenance ("O&M") costs and return on equity ("ROE") should be considered in addition to capital costs when assessing the viability of a solution. As the image below of real and nominal costs for transmission projects demonstrates, the true cost of transmission projects realized by the ratepayers is often around 10 times the initial price tag, over the lifetime of the assets.

Nominal costs

Asset value capital cost ($100 base)	$100
Return	$197
O&M	$631
Total nominal ratepayer cost per $100 investment (50 years)	**$928**

Real costs, discounted for inflation

Discount rate	2.19%
Asset value capital cost ($100 base)	$100
Return, discounted	$140
O&M, discounted	$296
Total discounted (real) ratepayer cost per $100 investment (50 years)	**$536**

In nominal dollars, total lifetime ratepayer cost is nearly 10x the initial capital cost; O&M accounts for 68% of this because it increases much faster than inflation. In real dollars (constant value dollars, accounting for inflation), the total lifetime cost is 5x the initial capital cost, and O&M accounts for 55% of this.

As a result, distribution-level solutions have the potential to be more cost-effective than transmission-interconnected resources, especially when factoring in the reduced congestion and line losses that comes from lowering the amount of energy that needs to be imported to the distribution grid. In comparison to bulk power resources, DER also create a large range of benefits due to value stacking potential. Therefore, the DPP should consider whether DER and distribution-level deployments can reduce the amount of money that needs to be invested in new transmission infrastructure. CAISO has demonstrated that the avoided transmission value is real by cancelling $2.6 billion worth of future projects during the 2017/2018 Transmission Plan due to DER and energy efficiency.[12]

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, even though many, if not most secondary distribution infrastructure would not meet the cost threshold for candidate deferral projects. However, understanding the cost of upgrading secondary distribution networks is imperative to ensuring that the state is on the pathway to achieving electrification. The recently released Kevala study on part 1 of Electrification Impacts suggests that secondary distribution upgrades and main service upgrades will cost around $15

[12] https://www.utilitydive.com/news/efficiency-ders-saving-26b-in-avoided-transmission-costs-caiso-says/519935/

billion (of a total of $50 billion worth of upgrades).[13] Understanding the pace of these upgrades and time/utility resources needed to complete the necessary upgrades will be important to understanding how costs should be allocated and guaranteeing that upgrades are completed in a timely fashion. In addition, having a better understanding of the scope of secondary distribution upgrades will improve the viability of energy storage or microgrids as candidates for deferring grid upgrades. The Clean Coalition believes this information should be included in the ICA Maps to create a more accurate/granular picture about what the cost responsibility will look like for developers that choose a particular location to site a project.

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).*

No comment.

Data Portals and Integration Capacity Analysis ("ICA") Improvements

ICA Maps will be essential to unlock the full value of DER and ensure that distributed generation projects can be sited in a way that reduces the need for grid upgrades and capitalizes on streamlined interconnection procedures. Since the Commission mandated their creation in 2017, the ICA Maps have been upgraded significantly to show capacity for both Generation and Load results on a platform integrated with DIDF results, LNBA results, and Grid Modernization results.[14] However, the ICA data is not granular or accurate enough to be used consistently by developers when making project siting decisions or in the ways envisioned by the Commission early in the Distribution Resources Planning ("DRP") proceeding (R. 14-08-013). For example, in D. 17-09-026, the Commission noted the value of ICA Maps and the DRP with the statement, "one of the key purposes of the DRP is to dramatically streamline the interconnection process," and responded to an assertion made by the ICA Working Group that ICA information could be very useful in the DPP by saying:

> We agree that ICA results should play a role in the distribution planning process, and adopt the ICA distribution planning use case. In the near-term, ICA results may be used to identify grid locations facing hosting capacity constraints in light of DER growth

[13] Electrification Impacts Study, Part 1. Kevala, at p. ES-6

[14] See D. 17-09-026, issued at the Commission on September 28, 2017.

scenarios that would be candidates for grid upgrades to accommodate projected DER growth. **In the future, ICA results may guide sourcing and procurement of DER solutions in specific locations with available hosting capacity and locational value**.[15]

Almost six years after that Decision was issued, the lofty goals that the Commission had for ICA data have not yet been fully realized. While ICA information is used as an input in the interconnection process, a study process conducted by a utility engineer must be completed before an applicant gets an accurate estimate for the cost of required upgrades to interconnect the proposed project. Even PG&E, who has the most advanced maps of the three IOUs has a disclaimer on its DRP website that states, "While the ICA and DIDF maps include the best information currently available, PG&E makes no representation as to the accuracy or quality of the data provided, its fitness for the purpose intended, or its usability by the recipient; PG&E cannot be held liable for inaccuracies or the impact of decisions made on this information."[16] As a result, the interconnection queues are still clogged with applicants that are seeking basic site/grid information, spending private money and using utility resources that would not otherwise need to be tied up if the ICA maps had reached the level of viability the Commission envisioned. Furthermore, there is a significant role for ICA data to play in terms of increased automation of the interconnection process that has not been fully explored and the concept of an Operational Profile still needs to be integrated into the Rule 21 interconnection process.

In terms of ICA Maps as a tool that benefits the DPP, improvements to the maps are necessary to demonstrate where targeted deployments of DER could have the most value and to better tie the results of the DPP in with DER integration and the IOU's grid modernization plans. Without accurate and granular data that provides actionable information, the value of the ICA Maps (and other maps on the platform) will be but a fraction as valuable as they could potentially be with the appropriate amount of investment. Given the Commission's dedication to the ICA Maps as essential to both the DRP and DPP, in addition to the need for an unprecedent amount of new capacity that must be sited over the next few years to meet reliability targets, the Clean Coalition firmly believes that a greater amount of attention should be paid to the ICA

[15] D. 17-09-026 at p. 27
[16] https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Maps, both in terms of validating the data (and improving the granularity) as well as increased investment to increase the pace with which refinements are being implemented.

As will be discussed further in the answers to the questions posed in the ALJ's ruling, the Generation and Load ICA data are at different sets of development. Generation ICA data has been improved significantly since 2018 albeit validation and improved granularity are necessary, especially if it is to be incorporated in the Rule 21 interconnection process. On the other hand, Load ICA data is still in its infancy and the data has not been validated to an extent where is usable for siting decisions and should be more granular. Moreover, the Load ICA data is not practical if the values are constantly being updated to account for new load growth; the data should include projects in the interconnection queue, known loads, load growth forecasts, and conversations with local municipalities/businesses.

Finally, the Commission should consider options to improve data sharing and three types of conversations: developers sharing lessons learned with other developers, municipalities planning for economic growth/new housing with utilities, and businesses discussing plans with large load impacts with utilities (such as fleet electrification). Therefore, the Clean Coalition recommends that part of Track 1 of this proceeding should reconsider the 15/15 Rule, which was implemented in the name of security/safety/customer privacy but is overly limiting. Since the Rule was approved in 2011, smart meters, improved communication standards, and increased DER adoption have changed the possibilities for, and benefits of, data sharing. The Clean Coalition concurs with a 2021 report by UC Berkeley School of Law's Center for Law, Energy & the Environment ("CLEE") and UCLA School of Law's Emmett Institute on Climate Change and the Environment that recommends, "the Public Utilities Commission could revisit and expand the 2011 decision to systematically classify all types of customer data (such as billing information) for their accessibility/portability, determine whether utilities should create different data sets based on data required for certain DER applications, and grant customers clearer rights to share a more complete set of their data with third parties for any type of DER."[17] We also suggest that the Commission considers an opt-out function (rather than opt-in) for ratepayers/developers that want to allow other groups to be able to learn from their experiences

[17] DATA ACCESS for a Policy Report DECARBONIZED GRID Policy Solutions to Improve Energy Data Access and Drive the Clean and Resilient Grid of the Future, February 2021, Climate Change and Business Research Initiative, at p.26
law.berkeley.edu/wp-content/uploads/2021/02/Data-Access-for-a-Decarbonized-Grid-February-2021.pdf

with ICA Maps and the interconnection process. Consumer privacy and grid security are essential, but it is also important to acknowledge that being overly restrictive with data results in a system where each new project is force to re-invent the wheel and enter a process blind to the experience of other similar projects. This proceeding, which is considering the intersection between the DRP, DPP, and Grid Modernization plans, should also take up the issue of data sharing and whether increased access could result in ratepayer savings (and streamlined interconnection).

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

Registration requirements act as a barrier to entry and only cause needless delays. For example, whether it is a business looking to site a project, a ratepayer curious about the local grid, or a utility in another state interested in creating hosting capacity maps, it does not make sense that each of the three IOU's have a different set of pre-requisites to access the ICA Maps. 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. The Clean Coalition does not believe that registration requirements should be necessary to view any of the maps. Each IOU's ICA Map should be immediately available without the need to sign in or request access. SCE's ICA Map provides immediate access without the need to register or create login credentials, demonstrating that registration requirements should not be construed as necessary for safety reasons. Moreover, while the Commission's statement in D. 17-09-026, "Continued standardization between the IOUs' modeling assumptions will thus drive consistency amongst the three IOUs' ICA results as they work to implement and maintain the models on an ongoing basis"[18] referred to the modeling assumptions, the same logic naturally applies to the map interfaces as well. For the maps to be as useful as possible, an interface that is user-friendly and consistent among the IOUs is ideal.

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

[18] D. 17-09-026 at p. 33

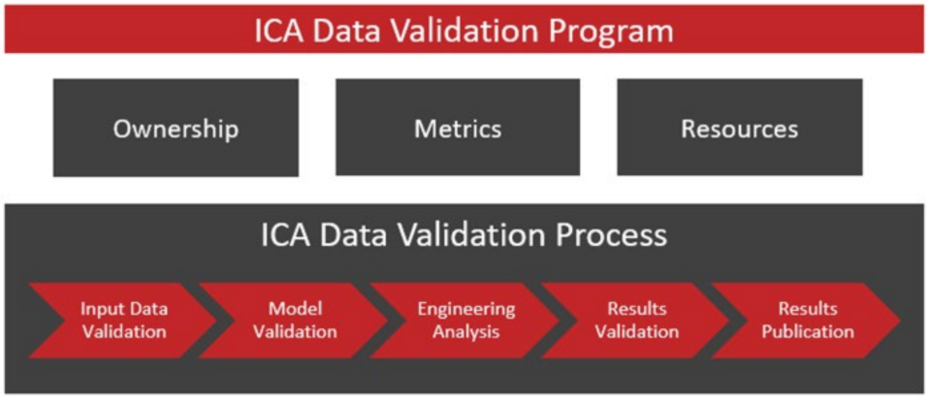
Yes, the Clean Coalition believes that data validation needs to be conducted on a feeder-by-feeder basis throughout each of the IOU-service territories to determine the accuracy of ICA data, particularly given the importance of ICA in the interconnection process. As we, and several other parties, have mentioned at recent workshops on ICA data, updates and improvements to the maps are essential but they mean nothing if the underlying data being built upon is erroneous or out of date. For example, when downloading feeder load profile data from SCE's DRP External Portal ("DRPEP") in a .xls file, it was clear that the last time the information was updated was 2018. If the base load profiles for ICA data are mainly built on historical load data, the older the data, the less accurate the final numbers will be.[19]

CIRCUIT_NAME	VOLTAGE	YEAR	MONTH	HOUR	MIN_LOAD	MAX_LOAD	SUBSTATION	MONTHLABEL
Professor	16KV	2018	9	15	22.43	38.28	Isla Vista	Oct, 15
Professor	16KV	2018	9	16	22.56	37.66	Isla Vista	Oct, 16
Professor	16KV	2018	9	17	22.51	36.33	Isla Vista	Oct, 17
Professor	16KV	2018	9	18	23.36	35.34	Isla Vista	Oct, 18
Professor	16KV	2018	9	19	23.3	34.59	Isla Vista	Oct, 19
Professor	16KV	2018	9	20	22.75	33.49	Isla Vista	Oct, 20
Professor	16KV	2018	9	21	22.15	32.25	Isla Vista	Oct, 21
Professor	16KV	2018	9	22	21.21	30.56	Isla Vista	Oct, 22
Professor	16KV	2018	9	23	20.24	28.81	Isla Vista	Oct, 23
Professor	16KV	2018	10	0	18.42	26.14	Isla Vista	NOV, 00

Circuit Load Profile for the Professor Feeder in Isla Vista, CA (in .xls format)

Inaccurate data makes it difficult to site individual projects, creating uncertainty for developers that rely on ICA data as an initial metric to screen projects for viability and for agencies attempting to design broader grid-level solutions that integrate local distributed generation. For example, decisions about siting charging infrastructure for a fleet of electric vehicles or determining where the initial footprint of a Community Microgrid should be located would be radically different depending on the historical load profile of the feeders, the available hosting capacity, and the cost of any required grid upgrades.

[19] Load ICA Refinements, Joint IOU/Energy Division Workshop, March 8, 2023, at Slide 19



[20]

The image above shows the process used to validate the quality of ICA data; currently SCE is almost finished with step four of five to correct errors with the Release 3. Last April, IREC informed SCE that the utility's ICA data was incorrect, leading SCE to submit a 30-day request for extension of time to comply with D.20-09-035 in July and a 180-day request for extension in August.[21] SCE's numbers were off by as much as 58% in some places and led to the number of circuits with 0kW of capacity under the operational-flexibility constraint increasing from 60% to 88%. Eight months later, a root cause analysis has been completed to isolate the problem, but a full solution has yet to be applied to every feeder in SCE's service territory.

The Clean Coalition appreciates the complicated nature of this work and the thoroughness with which SCE is working after IREC brought the issue to light. We hope that all the IOUs bring the same dedication when working on future ICA-related improvements. The transition required to achieve electrification will occur through unprecedented rates of DER deployment, which makes having an accurate ICA tool to helps make informed siting decisions essential. The issue with SCE's Release 3 underscores the large effect that even small errors can have and makes clear the need to have a party capable of ensuring the quality of results being produced. While both Generation and Load ICA data need to be checked for accuracy, Load ICA also needs to have the underlying methodology and inputs validated.

We have found the Generation ICA data to generally be more usable (and refined) than Load ICA data but have experienced inaccuracies with the Generation ICA data and are of the mindset that both should be validated for accuracy. Whereas Generation ICA data can often be

[20] 2021 Quanta Report on SCE's ICA Data Validation Plans, at p. iv
[21] Response to Southern California Edison Company's request for Extension of Time for Resolution E-517 from Executive Director

used for initial project siting, especially for preliminary discussions with the utility, Load ICA is not reliable enough for siting EV charging infrastructure ("EVCI"). Most developers looking to site EVCI prefer to submit interconnection applications to get definitive information from utility engineers, despite the added cost.[22] To meet the Commission's goals of streamlined interconnection, improved distribution planning and grid modernization, and harmonization with effective DER deployments, the ICA data for both Generation and Load needs to be accurate throughout each of the IOUs service territories on a consistent basis. Updates also must be made frequently enough that the information presented reflects the expected interconnection experience.[23] This type of actionable information should, "provide an adequately representative value to inform developer project design and siting and for use in the interconnection process."[24] As the state trends toward real time rates and demand flexibility, it will be necessary to have conversations about what is the appropriate frequency for ICA data updates.[25]

a. *Who should evaluate the accuracy of the Generation ICA and Load ICA data?*

The Clean Coalition is less concerned about who evaluates the accuracy of ICA data than ensuring the data is validated for accuracy in the first place. Furthermore, we believe that reconsidering existing data privacy practices could make it easier to validate feeder data and help developers to incorporate lessons learned from each other. We believe that the 15/15 rule should be reconsidered to make data transparency the default position. Rather than limiting access to information irrespective of a developer's wishes, a developer would be able to opt-out to allow for confidentiality of a sites' load profile if specifically requested.

b. *What metrics should be used for assessing the ICA data accuracy?*

No comment.

c. *How frequently should the accuracy of the ICA data be evaluated?*

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[22] Comments of EV Charging Companies at March 8, 2023 Load ICA Refinements Workshop

[23] Here, interconnection experience can be understood as the same approximate cost for upgrades and feeder limits and is not referring to the exact timeline or any application-deficiencies.

[24] D. 17-09-026 at p. 14

[25] "IOUs support system-wide monthly updates for initial rollout with consideration of higher frequency updates on case-by-case, on demand, or weekly basis. Other WG stakeholders believe ICA should be updated annually system-wide, and that specific nodes/feeders be updated weekly to reflect queued projects, new interconnections, or other system changes above a defined threshold." D. 17-09-026 at p. 13

The frequency of data validation depends on how often the data is being updated by the IOUs. Data should be evaluated on a feeder-by-feeder basis at least once each year. However, by the time real time rates rolled out, demand flexibility becomes commonplace, and ICA data are fully integrated into the interconnection process, it could make sense to evaluate the data bi-annually or even quarterly. On a more granular level, it makes sense to have a separate procedure where the data for individual feeders—or groups of feeders in the same area—can be validated on a much quicker timeframe.

d. What is an appropriate timeline for implementing the accuracy improvements?

No comment.

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?

The primary question is what the specific constraint causing the low hosting capacity is, which is what will determine the possible remedies. The ICA User Guides state that either thermal, voltage, distribution protection, or operational flexibility violations could be the issue, but the maps don't currently show the specific violation limiting the integration of generation. This is not user friendly; a developer should not need to download data or reach out to utility engineers to get clarity. Instead, each feeder segment should be more transparent and indicate the limiting factor to the integration of more generation. With information about the limiting constraint, the next question is what the cost of the upgrade will be, whether there is a behind-the-meter ("BTM") solution that might avoid the upgrade, or if downsizing the project is possible. Depending on the cost and timeframe to implement solutions, a developer might prefer to search for another location rather than work to develop a project at a site with 0kW of hosting capacity.

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

Given the investment that has already been made in the ICA Maps and California's role as a leader in the space, the Clean Coalition believes that it is most prudent to continue investing in improving the accuracy/granularity of these maps. Moreover, there is a need for actionable information that can be used in the interconnection process and the utilities/parties are most familiar with the ICA maps. We do not believe that there is a reason to start over with another tool, particularly given the fact that other tools have not been developed to a point where they might provide better information than the ICA Maps themselves.

14. *For which types of projects is Generation ICA most useful? Be specific as to the size of the project (nameplate capacity less or greater than, X kW,), type of project (solar, storage, other), its service tariff (Net Energy Metering, Net Billing Tariff, other) and how useful (very useful, somewhat useful, or not useful) the ICA data is for each project type.*

No comment.

15. *What are the most critical Generation ICA improvements needed to facilitate siting of DERs and streamline DER interconnection? How should these improvements be made?*

First, the Clean Coalition believes that the Limited Generation Profile should be fully integrated into the Rule 21 interconnection process, which will require accurate data that has been validated for quality. Second, each of the IOU's ICA maps should provide an easy way to download the ICA spatial data in multiple formats (GEarth, geodatabases, etc...). So far, PG&E and SDG&E, allow users to download just ICA geodatabases, 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. Third, the ability to consider more granular levels of data, down to a structure level, would be helpful when considering the ability to integrate more generation.

16. *For which types of projects is Load ICA most useful? Be specific as to the size of the project (nameplate capacity less or greater than, X kW,), type of project (solar, storage, other), its service tariff (Net Energy Metering, Net Billing Tariff, other) and how useful (very useful, somewhat useful, or not useful) the ICA data is for the project.*

Load ICA is not currently useful because the data is inaccurate (it does not effectively incorporate load growth forecasts) and lacks sufficient granularity. While the information can provide general information about feeder data, it cannot be used for predictive purposes related to interconnection. For example, EV companies are unable to use the information to site charging infrastructure and instead rely on submitting Interconnection Applications to get reliable information from utility engineers. This is true for both public charging banks as well as businesses looking to electrify their fleets.

17. *Utilities filed plans to improve their Load ICA maps in February of 2022.*
    a. *How do the Utilities' proposed Load ICA improvements align with and support the goals of Electric Vehicle (EV) load siting and building electrification? What further improvements are needed to advance accuracy and usefulness?*

The plans should include locations where grid hardening activities, such as substation or feeder upgrades, are occurring to help developers focused on network planning (such as EV companies or developers looking to site batteries as part of a VPP).

b. *Given the Utilities' stated implementation timeline of 2025/2026, what near-term steps can Utilities take to improve the Load ICA?*

Of the three IOUs, SCE has a plan to roll out Load ICA improvements by Q1 2027, PG&E by Q1 2025, and SDG&E by Q4 2025. Hopefully, SCE's timeline can be expedited to better match the timeline of the other two utilities. Having to wait almost four years before improvements are complete is not ideal, given the need to site charging stations for more than 1.5 million new EVs (based on reaching former Governor Brown's target of 5 million EVs by 2030) within that same timeframe. Additionally, the IOUs should strive to ensure that Load ICA data provides actionable information rather than only offering directional information that cannot be used to determine what the interconnection process will look like. An important aspect of reaching the high bar of actionable data will require increased granularity and validating the data to ensure that the underlying modeling assumptions are producing the correct results.

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

The Clean Coalition believes that this question should be considered when we have a better understanding of the scope and potential of load flexibility. Since load flexibility will primarily be a tool to reduce the peak load, flexibility on a feeder does not necessarily mean that there will be sufficient capacity to add a load that is pulling energy from the grid throughout the day.

DPP Alignment with Transportation Electrification

19. How can Utilities be proactive in planning distribution upgrades for EV adoption and associated EVSE installations? Who should Utilities collaborate with to identify EV locations and forecasted loads?

As discussed above in relation to community engagement, being proactive necessitates a framework to encourage two-way conversations with community leaders, businesses, and residents (rather than solely relying on those parties to initiate dialogues). It would also be beneficial to have statewide maps of sites where EV charging infrastructure will likely be deployed, based on existing to travel corridors and regional/urban centers. The IOUs should also move from backwards looking predictive models to forward looking models; historical DER adoption rates will not necessarily be predictive for EV adoption in DACs going forward.

Increased funding from the federal government, state government, and equity-specific funds will help improve the pace of adoption and proactively siting EV chargers will help solve the chicken-egg problem.[26] Finally, the IOUs should consider solutions to deploy EV charging infrastructure without triggering grid upgrades, such as dedicated microgrids that can island and handle the increased load from EV charging with BTM generation and energy storage, rather than solely importing from the grid. Extending the use of Limited Generation profiles to load profiles could also help by ensuring that chargers sited in constrained grid locations only import during off-peak periods where there is extra capacity.

20. *How should Utilities plan for broader transportation electrification including Medium-Duty and Heavy-Duty EVs, fleet, freight, and ports?*

No comment.

   a. *How will Utilities meet the short-term needs of the added demand from Medium-Duty and Heavy-Duty EV fleet and depots?*

No comment.

   b. *How can Utilities employ targeted DERs and load management strategies to meet the added load from Medium-Duty and Heavy- Duty EV fleet and depots?*

No comment.

21. *How should Utilities ensure they have sufficient grid capacity and DER visibility to efficiently implement the secondary distribution infrastructure, non-wires alternatives, and load management strategies required to support the Transportation Electrification investments envisioned through 2030?*

No comment.

DIDF Reform

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.*
    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.*

All the above. Greater amounts of information will only improve the planning process and ensure that the grid will enable electrification rather than acting as an impediment.

[26] Customers living locations where EV chargers do not already exist are less likely to adopt and EV because it is not convenient than their counterparts who have an abundance of charging stations near them.

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?*

Given the importance of building out the grid to meet electrical demand as it increases by 68%, overbuilding should not be a driving force in reforming the DIDF. The Clean Coalition is certain that the full number of potential opportunities for DER deferral are not being taken advantage of under the current DIDF. Increasing the number of candidate projects actually deployed to defer grid upgrades beyond the status quo should be considered a success.

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?*

The Commission should consider ways to increase the number of holistic investments that benefit the ratepayers rather than solely focusing on achieving ratepayer savings exclusively as a function of lower cost deferrals as compared to traditional wires upgrades. The existing framework does not compare the full range of costs over the lifetime of the assets, only the up-front capital costs. As a result, the cost cap for DER deferral does not account for the significantly higher O&M costs for traditional infrastructure investments versus a DER solution. Moreover, a least cost best fit framework does not capture the full range of costs and benefits that a benefit cost analysis would.

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

Yes. The Clean Coalition is not aware of any resilience of backtie projects deployed under the DIDF, despite clear needs for increased resilience across the grid over last four years. The DPP should better incorporate desires for resilience from communities and consider locations that have been hit by long-duration outages or have gone through multiple outages (including PSPS or Fast Trip Outages). All types of microgrids can provide grid services or defer utility infrastructure upgrades, including BTM microgrids and Community Microgrids; microgrids provide an unparalleled trifecta of economic, environmental, and resilience benefits.

Furthermore, the DIDF should consider locations where there are multiple needs. For example, in a situation where a capacity upgrade is required, a microgrid that meets the need via energy storage and provides resilience offers the most value to the ratepayers. In terms of the grid of the future, deploying a greater number of microgrids particularly makes sense as the state transitions to a framework centered around DSOs.

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?*

One of the issues with BTM DER deferral has to do with the timeframe in which a solution must be deployed. Ensuring that a resource will be deployed within 18-36 months is difficult without a guarantee that the interconnection process will proceed smoothly. Fast Track interconnection will improve the likelihood that developers will be interested in bidding and that projects will be deployed in time to meet the need. In addition, the ability to provide other distribution grid services or value stack will increase the viability of deferral projects for potential bidders, making discussions about DSOs and distribution-level markets all the more important. The Clean Coalition also believes that CCAs and local governments could submit bids if an appropriate incentive is put in place.

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

Bidder uncertainty is always a challenge that must be managed when designing successful programs. The more certain that deploying a project is, the more likely a developer is to be to take on the risk associated with making a bid. As mentioned above, Fast Track interconnection will increase certainty, as will ensuring that an executed contract will not be cancelled for an ambiguous reason. Finally, having a developer that can bid on more than one contract at the same time (by submitting a bid that is under the collective cost cap) would help incorporate economies of scale.

IV. CONCLUSION

The Clean Coalition appreciates the opportunity to submit these comments and looks forward to continuing the dialogue about the DPP and changes that need to be made to enable a cost-effective pathway to electrification.

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