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)

REPLY COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE ORDER INSTITUTING RULEMAKING TO MODERNIZE THE ELECTRIC GRID FOR A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits these reply comments on the *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* ("OIR"), issued by the Joint Commissioners on June 24, 2021.

I. INTRODUCTION.

CESA reiterates our welcoming of this proceeding to leverage distributed energy resources ("DERs") in the California grid. The Commission is appropriately focusing this proceeding on how to fully enable and leverage DERs considering California's pressing issues to manage grid reliability in the face of increased need for renewable energy integration, growing levels of electrification load, resiliency needs in the midst of the state's continuing wildfires and extreme weather events, and growing rates and customers and communities that would like to have their own energy assets. Considering all of these issues, setting an appropriate scope and schedule will be key. To this end, CESA's comments can be summarized as follows:

- The Commission should adopt Compromise Schedule A.

- Performance-based regulation ("PBR") should be included in the explicit scope of this proceeding.

- This rulemaking should have more expansive consideration of infrastructure and tools needed to accommodate and enable distributed energy resources.

CESA's recommendations are based on the need to make progress on some of the important big-picture vision and reforms to the distribution planning process ("DPP") and the role of the investor-owned utility ("IOU") under a potential distribution system operator ("DSO") model, as well as potential significant grid infrastructure investments in tools and platforms to realize these reforms; however, it is equally important to ensure that this proceeding makes incremental changes in the near term that improve upon the Distribution Investment Deferral Framework ("DIDF"), key data tools and access considerations as it relates to Distribution Resource Plan ("DRP") portals and Integrated Capacity Analysis ("ICA") methodologies, and broadly enabling DERs in their provision of grid services. The right balance between near-term and long-term reforms needs to be struck to avoid poor outcomes where DER deployment and operationalization is stalled or slowed, or not fully enabled to meet the ambitious decarbonization goals set forth in Senate Bill ("SB") 100.

II. THE COMMISSION SHOULD ADOPT COMPROMISE SCHEDULE A.

CESA reiterates our position that it is important to allow for near-term progress within this large proceeding that is also considering large structural reforms to how DERs integrate into our grid. In opening comments, CESA proposed to set aside near-term issues, including supporting transportation electrification ("TE"), ICA improvements, enabling DER aggregations, and other carryover issues in a separate Track 1. Upon reviewing the Commission's consolidation and synthesis of party comments into five revised or compromise schedules, CESA believes that Compromise Schedule A represents the best schedule that aligns with our recommendation and allows for discussion and earlier decisions on near-term issues while also keeping the schedule simpler for parties and advancing the proceeding on more complex longer-term reforms and policy issues.

Specifically, CESA prefers Compromise Schedules A and B because of their inclusion of a Proposed Decision ("PD") in Q1 of 2023 on near-term issues including urgent TE and grid modernization needs, as well as the addition of DER Management Software ("DERMS") to the Smart Inverter Operationalization ("SIO") track. Including a near-term PD in Q1 2023 is crucial to ensuring that California is well prepared for future electrification, which is already well underway, and can help to ensure mid-term reliability given that longer-term DSO reforms may take years of implementation. There may very well be actions that can be taken in the near term to better enable and accommodate DERs through key process and tools improvements in the interim instead of delaying such action or consolidating the resolution of "low-hanging fruits" with more complex or longer-term policy issues. Including DERMS alongside SIO is also prudent given that these two pieces of technology will interact in close coordination, and stakeholder input on how to optimize these together will be valuable. Lastly, the Commission should make decisions on these items in the nearer term, as proposed by the compromise schedules, in order to give utilities ample time to set up and refine their rollout of their DERMS systems. While these schedules slightly delay the beginning of the DSO white paper development, CESA believes that work could still begin on this issue next year with workshops before the white paper to begin discussions on issues such as PBR-related incentives, penalties, and rules.

While both Compromise Schedule A and B include the same items with PDs to be issued in the same timeframes, CESA finds Compromise Schedule A to be preferable to B because of its simplicity. Having five separate tracks will make it harder for parties to keep track of the issues they would like to engage with, given that many parties will likely want to participate in multiple tracks, and may overlook the intersections or interrelations of various issues. While many parties will still likely want to participate in multiple tracks even in a three-track schedule, CESA believes the alignment of Tracks 1-3 in Schedule A (*e.g.*, the grouping of DIDF issues, electrification impacts, and DPP) will allow most parties to effectively cover items of interest to them, without the burden of extra tracks.

By contrast, CESA does not support the adoption of Revised Schedules 1 and 2, which would (1) remove the consideration of grid modernization investments and General Rate Case ("GRC") alignment altogether from this proceeding, and (2) delay grid modernization considerations to Q3 2024, respectively. The specific grid modernization investments appropriately belong in GRC proceedings, where the specific proposed investments, costs, and benefits are quantified and examined, but this proceeding is appropriately scoped to consider the needs for grid modernization investments as a policy matter. In addition, there may be priority grid modernization investments that need to be identified and directed in the near term, as explained further in our reply comments below, that support the goals and objectives of this proceeding, even as the IOUs ultimately addresses specific investments, proposals, and costs in the GRC proceedings. For example, in support of the California Independent System Operator ("CAISO") Order No. 2222 compliance, which will naturally involve coordination with the Commission as the local regulatory authority ("LRA"), this proceeding should prioritize near-term grid modernization investments that enable coordination of the transmission and distribution interface, accommodating DER aggregations as a result. To this end, Compromise Schedule A best accommodates these considerations, where a Track 1 Phase 1 PD is targeted for Q1 2023.

III. PERFORMANCE-BASED REGULATION SHOULD BE INCLUDED IN THE EXPLICIT SCOPE OF THIS PROCEEDING

As raised in the OIR and multiple parties opening comments, including those of CESA, PBR should be explored as a potential regulatory and rate tool to remove barriers to DER deployment and build a sustainable future for customers, DER providers, and utilities alike. As highlighted by the Center for Biological Diversity ("CBD"), "the [Commission] can no longer treat the fundamental tension between utility business models and DER expansion as a background issue that regulators can navigate gently."[1]

Multiple parties highlighted how the traditional utility business model relies on a fixed rate of return on investments.[2] The Environmental Defense Fund ("EDF") opined that Commission directed investments with a traditional rate of return "should be sufficient to incent proper investment."[3] PG&E also states that they, "[do] not believe that a lack of utility-incentives is impeding the advancement of DER deployment and integration."[4] However, EDF and PG&E still focus on shaping a high-DER future where DERs are utility distribution assets, with PG&E stating that this proceeding should focus on "how to enable utilities to directly invest, own, and operate DERs as distribution assets."[5] Improvements could definitely be made in aligning incentives to be more indifferent to DERs versus traditional distribution infrastructure, but narrowly focusing questions of utility incentives on utility ownership and operation severely reduces the roles that DERs can play in the future grid and limits the abilities of communities to be able to make investments in their own energy. PBR has the potential to reduce barriers for third-party and

[1] CBD Comments at 5.
[2] CBD Comments at 5, Local Government Sustainable Energy Coalition Comments at 5-6, Microgrid Resources Coalition ("MRC") Comments at 12-13, The Utility Reform Network ("TURN") Comments at 3.
[3] EDF Comments at 5.
[4] PG&E Comments at 6.
[5] PG&E Comments at 6.

community-owned DERs and give utilities a financial or regulatory incentive to advance rather than just accommodate a high DER future. For these reasons, CESA believes that PBR should be thoroughly explored in this proceeding and recommends specifying this in the question currently listed in Track 1, Question 4, to the language proposed by the Vehicle Grid Integration Council ("VGIC"):

> "Should the IOUs be incentivized to cost-effectively prepare for widespread DER deployments? <u>How can performance-based regulation (PBR) and performance-based incentives be used as a tool to prepare for DER deployment? What other modifications to the existing utility incentive structure should be considered to prepare for DER deployment?</u> ~~If so, how?~~"[6]

Given these considerations, Protect Our Communities Foundation ("PCF") argues that this rulemaking should be designated as ratesetting instead of quasi-legislative, stating that the proceeding will be "reviewing the way that the IOUs earn profits. Redefining the way utilities earn money in a way that could even go as far as to restructure the rate of return clearly aligns with Rule 1.3(g)'s definition of a ratesetting proceeding."[7] While CESA agrees that any development of PBR will involve rates, we believe that this proceeding should instead focus on the policy implications and broader merits and costs of PBR as a policy and rate framework. The goal of this proceeding should be to determine whether a PBR framework should be developed by the Commission. These issues and discussions can occur in a quasi-legislative setting; therefore, CESA believes that this proceeding should remain designated as quasi-legislative. Any specific PBR tariff would fall outside of the scope of this proceeding and would instead have to be set in a ratemaking proceeding and considered in the General Rate Cases ("GRCs") for all load-serving entities ("LSEs"). Alternatively, a separate ratesetting track or phase could be initiated if and when

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[6] VGIC Comments at 6.
[7] PCF Comments at 2.

PBR frameworks are established and PBR tariff development is then needed. However, these are important conversations to begin, since, as the Microgrid Resources Coalition summarizes, "incentive ratemaking, as such, is beyond the proposed scope of this proceeding, but unless the Commission is ready to substantially revise utility incentives, discussion of high levels of DER will prove, we fear, to be empty talk."[8]

IV. THIS RULEMAKING SHOULD HAVE MORE EXPANSIVE CONSIDERATION OF INFRASTRUCTURE AND TOOLS NEEDED TO ACCOMMODATE AND ENABLE DISTRIBUTED ENERGY RESOURCES.

Enabling DERs will include many technical aspects, including smart inverters, DERMS, cybersecurity tools, and more. Based on the OIR and the discussions at the scoping workshop, the consideration of grid infrastructure and tools in this proceeding is focused on how to facilitate and optimize DER siting, interconnection, provision of distribution grid services, and reflection of community needs, as well as the determination of the appropriate distribution investments to support load growth and operationalization of DERs. In this sense, the Commission is focusing on how to accommodate a high DER future in terms of its impacts and costs to the distribution system.

However, CESA believes that such a focus of grid infrastructure and tools is overly narrow and does not consider the grid infrastructure investments and tools necessary to enable and accommodate DERs to support the Commission's broader DER objectives, including to facilitate their wholesale market integration, enable the full utilization of DERs like energy storage, and, most importantly, realize the various tracks outlined in the DER Action Plan 2.0. One particular area that should be explicitly scoped into this proceeding as potential near-term grid modernization investments is the consideration of billing and settlement infrastructure to enable the high-DER future. Regardless of any specific DER tariff, rate, or program, improved and advanced billing and

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[8] MRC Comments at 12.

settlement infrastructure may be needed to support the integration of and compensation for DERs to provide either its full range of services or to provide granular dispatch and response. As the role of a DSO is considered, particularly as ideas surrounding distribution transactions to compensate for energy, capacity, resiliency, or ancillary services, billing and settlement needs should also be considered.

This is particularly relevant given the fact that the inadequacy of the billing and settlement infrastructure have limited advancements in operationalizing DERs and have been cited as a barrier to real-time pricing ("RTP") tariffs and sub-metering of energy storage. Recently, in Decision ("D.") 21-07-010 issued to conclude the San Diego Gas and Electric Company ("SDG&E") General Rate Case ("GRC") Phase 2 Application, the need and complexities of billing system upgrades were highlighted as barriers to near-term RTP implementation.[9] In light of Commission staff's proposal for a unified, universal, dynamic, economic energy signal, or "UNIDE" framework and the California Energy Commission ("CEC") development of load management standards, any necessary grid modernization investments to enable a future where multiple dynamic rate options are provided to all customer classes must be identified and potentially directed as a policy matter in R.21-06-017, followed by specific and subsequent consideration and approval in future GRC filings. Multiple action elements in the Draft DER Action Plan 2.0 are explicitly targeting a future where dynamic rate options are broadly available and accessible, yet it is unclear whether the forthcoming Load Flexibility Rulemaking will scope in such considerations. Therefore, without the necessary billing and IT infrastructure in place, this vision element will be challenged to be realized. As an infrastructure investment that enables and accommodates DERs for grid services via advanced rate design, it is appropriate to consider within this proceeding.

[9] D.21-07-010 at 56:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K302/393302635.PDF

Similarly, billing and settlement infrastructure limitations have been cited as limiting factors for the Commission to adopt sub-metering and direct measurement methodologies. In the Demand Response ("DR") Applications (A.17-01-012, *et al.*), for example, the Commission determined that:[10]

> "At this time, we decline to adopt or authorize the use of the Meter Generator Output as a baseline method in the Auction Mechanism. As noted by SDG&E, Council, and PG&E, this is not the appropriate proceeding, as certain issues would not apply solely to the current models of demand response. In comments to the proposed decision, CESA disagrees with this contention arguing that the Meter Generator Output baseline was adopted by the CAISO in the Energy Storage and Distributed Energy Resources Phase I initiative for the explicit purpose of measuring the performance of demand response resources with storage. CESA's statement acknowledges that the Meter Generator Output baseline was adopted by the CAISO to measure performance of demand response resources with storage in a forum focused on distributed energy resources. Accordingly, the Meter Generator Output baseline should not be considered in a proceeding that solely addresses demand response."

In the ongoing Emergency Reliability Rulemaking (R.20-11-003), Pacific Gas and Electric Company ("PG&E") also raised various issues with subtractive billing to enable submetering approaches and the "pros and cons" of device-level settlement.[11] Consistently, any deeper consideration of enabling sub-metering or direct device-level measurement and settlement of energy storage and electric vehicle ("EV") chargers has been deferred, often pointing to how there are billing and settlement system limitations to their enablement. However, to realize the full-range discharge potential of stationary and mobile storage systems and not necessarily be limited by baselines or load limitations under a DR construct, these issues must be addressed, which may

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[10] D.19-07-009 at 81-82:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713644.PDF
[11] See PG&E Opening Brief in R.20-11-003 at 12:
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M409/K894/409894233.PDF
See also PG&E Reply Brief in R.20-11-003 at 23-24:
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M407/K998/407998699.PDF

involve consideration of billing or settlement system enhancements if such deficiencies are specifically identified. To date, this type of infrastructure consideration has been deemed out of scope of multiple proceedings, including but not limited to A.17-01-012, *et al*., R.20-11-003, and R.15-03-011, and may be similarly deemed out of scope of the forthcoming 2023-2027 DR Application, Load Flexibility Rulemaking, and/or a successor Energy Storage Rulemaking. More importantly, given the objectives and focus of R.21-06-017, this proceeding is appropriate to focus on these needs since R.21-06-017 has objectives aimed to further enable and accommodate DERs and will potentially consider grid modernization investments that not only better enable DER aggregations and export-capable DERs but also advanced load flexibility in the form of RTP and dynamic rates.

In response to potential concerns from the Commission and some parties who may deem DER billing and settlement issues as out of scope since this proceeding is focused more on optimizing siting, interconnection, investments, and distribution grid services, CESA urges the Commission to not narrowly focus this proceeding in such a way. There are spillover benefits of potential infrastructure investments and enhancements in billing and settlement systems that can not only increase the utilization and value of DERs participating in DIDF solicitations, tariffs, and programs for distribution grid services,[12] but also to support DER utilization for system and grid-wide benefit. As the CEC staff presented at the scoping workshop, DERs need a value stack, where distribution service or deferral value alone will not optimize DER investments, such that every effort should be made to enable DERs to compete and potentially provide the full value stack.

[12] Even within DIDF, customer-sited energy storage and DR resources are limited by customer load and does not settle using sub-metering or direct measurement approaches. To this end, this issue could still be viewed as within the scope of this proceeding with a narrow distribution focus.

At the same time, CESA emphasizes that we are not advocating for the broader consideration of DER tariffs or compensation structures. Those issues, beyond the specific consideration of tariffs and compensation for distribution grid services, likely belong in other appropriate proceedings. However, any discussion on proposed markets should consider the technical data and infrastructure needed to enable the proposed market (*e.g.*, submeters, granular time data, telemetry, etc.) for systems responding to day-of markets or real-time pricing. CESA believes that these issues should be explored as a Track 1 item under Compressed Schedule A as a potential near-term grid modernization investment priority.

V. RESPONSES TO WORKSHOP QUESTIONS.

Following the scoping workshop on September 22, 2021, CESA provides our responses to the questions posed during the workshop in order to guide the development of the Scoping Memo.

Question 1: What near-term activities should be prioritized and how should the tracks or schedule be modified to prioritize them? Should a new Track 1 be developed for near-term activities?

CESA reiterates our position that there are important near-term issues that should be addressed and decided before the release of PDs on structural DSO or DPP issues. Among these issues, CESA believes that TE and VGI issues will be increasingly important, alongside data portal enhancements, ICA improvements, and collaboration with community stakeholders.

a. Should the CPUC align forecasts used for distribution investment planning to reflect state electrification policy? If so, how should investor-owned utility (IOU) Distribution Planning Processes (DPPs) change to reflect these forecasts?

Yes, CESA believes that load forecasts should include state electrification policies, particularly forecasts for TE goals. As stated by SCE and SDG&E,[13] California has ambitious TE goals, including Governor Newsom's Executive Order requiring all new cars and passenger trucks sold to be zero-emission vehicles by 2035.[14] Not reflecting this clearly stated goal in the CEC's Integrated Energy Policy Report ("IEPR") forecast does not make any sense and should be remedied as soon as possible. As it becomes clear where high EV adoption is likely to occur, IOUs should begin anticipating where investments are needed. As highlighted by SDG&E, updated forecasts "will support the identification of near- and longer-term infrastructure needs, which will be reflected in the utilities' GNA reports. This, in turn will provide increased opportunities for DERs through the DIDF processes."[15] SCE also highlights that including "policy-based forecasting" will allow utilities to leverage long-lead time, least regrets solutions to serve these load needs. CESA also supports SCE's call for improved data sharing between state agencies, utilities, load-serving entities, and third parties to allow for more accurate and granular forecasting to help identify locations of high electrification and grid needs.[16] This issue should be taken up in as near-term issues within a track.

b. Should the IOUs make specific modifications to their DPPs to enable strategic, long-lead time transportation electrification (TE) and building electrification (BE) grid investments? If so, how should the DPPs change?

[13] SCE Comments at 2, SDG&E Comments at 20.
[14] Executive Order N-79-20.
[15] SDG&E Comments at 14.
[16] SCE Comments at 12.

Yes, CESA believes that addressing this question should be included as a near-term Track 1 issue in our recommended Compressed Schedule A. In our experience in the Distribution Planning Advisory Group ("DPAG"), CESA believes that there could be many improvements made in this regard, where the current DIDF is reactionary to EV load applications and does not always assume a charging profile that matches EV rate structures. With more proactive approaches and/or incentive structures for EV load connections to realize distribution investment cost savings, CESA believes that DPPs can be improved in supporting both near- and long-term TE charging infrastructure buildout.

c. Should the proceeding prioritize IOU integration of DERs into their standard DPPs, and if so, how?

Yes, CESA agrees with SCE that DERs should be directly incorporated into utility DPPs to be considered for their wholistic and unique benefits, instead of only being considered for specified distribution deferral. The current DIDF only allows for DERs to be procured in place of specific distribution upgrades that were going to be undertaken by the utility. By incorporating DERs as direct resources in the DPP, utilities can more creatively think of how to optimize a grid and leverage DERs for their unique abilities, such as load modification abilities, instead of merely considering them as non-wires alternatives to a planned distribution system wire upgrade.

d. What DRP Data Portal improvements (e.g., Integration Capacity Analysis [ICA] data accuracy, portal usability, additional types of data) are needed to support TE planning, siting, and integration of electric vehicle supply equipment?

During the scoping workshop, many parties raised the urgent need for data sharing and data portal improvements, particularly given the near-term electrification of transportation and buildings. The CEC's Big Data and Distribution Resource Planning Market Study highlights the need for more granular data to be shared between DER providers, utilities, and public agencies.[17] Recent work in R.14-08-013 also highlights the importance of improving the ICA, and how this tool is a crucial for parties for planning, including planning for TE investments. However, as raised by parties during the workshop, these issues should be prioritized for near-term work and decisions.

e. Is it necessary for the CPUC to resolve Smart Inverter Operationalization (SIO) issues in advance of considering improvements to the Grid Modernization Framework and General Rate Case (GRC) alignment? If so why and which issues?

CESA does not believe that SIO issues need to be resolved before discussing improvements to the Grid Modernization Framework. The Grid Modernization Framework is broad and discusses a variety of issues, including policy issues such as customer engagement, distribution markets, and long-term planning. Stakeholders are also likely to have robust opinions on the previous Grid Modernization Plans ("GMPs") submitted by utilities and how to improve the current Grid Modernization Frameworks. CESA agrees that it will be helpful to have SIO issues resolved to include in any decisions regarding updated Grid Modernization Frameworks. However, there should be plenty of topics to begin discussing while SIO issues are being worked out.

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[17] Lyon, Erik, Tom Flynn, and Hilary Poore. 2021. *Big Data and Distribution Resource Planning Market Study*. California Energy Commission. Publication Number: CEC-200- 2021-007.

f. How should data sharing between utilities and state agencies be improved (e.g., CPUC, CEC, CARB, CAISO)?

As raised by various parties during the stakeholder workshop, data sharing will be important in moving towards a high-DER future, and improving data sharing between utilities, state agencies, third-party DER providers, and customers should be a near-term focus area for this proceeding. CESA also supports SCE's calls for state agencies to share more granular and location-specific data in order to improve electrification (both TE and building electrification) forecasts.[18]

CESA also believes that the Transmission and Distribution Interface Working Group raised a variety of data sharing issues that can be further explored in this proceeding. Gridworks highlighted more specific data-sharing that will be needed as we enter a high DER future and distribution market transactions,[19] and pathways to enable that data-sharing should be discussed in this proceeding.

Question 2: In what ways is it important that specific findings from the following three study areas inform Track 3's Grid Modernization Plan Improvement and GRC Alignment Staff Proposal (i.e., grid modernization decisions that would result in costs to ratepayers being evaluated in IOU GRC filings)? Should studies for these areas be completed prior to considering Grid Modernization Framework updates, and if so, why?

CESA believes it is important to incorporate findings from all three studies into future Grid Modernization Framework updates. All three studies have implications for GMPs and investments, and it is important to incorporate these findings into GMPs so that long lead time, least regret investments can be made to enable a High DER future. However, CESA does not believe that these

[18] SCE Comments at 14.
[19] Gridworks, "Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid", presented on May 17, 2021.

studies need to be fully completed before updates to the Grid Modernization Framework are made, since stakeholders may raise urgent changes that are needed to enable DERs in the near-term or improve ratepayer investments.

a. Future Grid Study (Distribution System Operator [DSO] roles and responsibilities, grid vision, grid architecture)

Currently, deeper considerations of larger distribution markets and operationalization of DERs are not included in the utility GMPs. The structural changes that may occur with the adoption and implementation of DSO functions, whether by utilities or a third-party DSO, will dramatically impact future grid investments. The technology needed to facilitate these market transactions, including metering equipment, telemetry, DERMS, cybersecurity, wireless networks, will likely be procured by utilities and funded by ratepayers. It will therefore be prudent for the results of the Future Grid Study to be incorporated into utility GMPs.

b. SIO working group (SIOWG) report and subsequent staff proposal

The SIOWG report will heavily impact grid modernization considerations and utility GMPs. Smart inverters will play a large role in enabling DER controls and integration into any larger energy markets. Therefore, utilities will likely leverage smart inverters to enable their GMPs and include smart inverters and technologies needed for their operationalization as part of their investment plans.

c. Electrification impacts (study and subsequent staff proposal)

Electrification impacts will heavily influence GMPs by determining what grid needs will be. By having accurate electrification forecasts, utilities will be able to determine areas in need of upgrades or potential areas for non-wires alternatives and include relevant investment needs in their GMPs.

Question 3: **Before adding new community engagement requirements to IOU DPPs, should a needs assessment be conducted to understand what communities want and need from the DPPs? If so, how should the needs assessment be conducted (e.g., third-party focus groups, surveys, workshops, studies)?**

CESA has no comment at this time.

Question 4: **Should we include within the scope of the SIOWG an evaluation of existing cybersecurity standards that should be applied? What cybersecurity issues are unique to DERs?**

CESA has no comment at this time.

Question 5: **To what extent should the SIOWG focus on DERMS and IOU capabilities to dispatch DERs to perform grid services? What existing standards should be considered (e.g., IEEE 2030.11-2021 on DERMS interoperability)?**

CESA supports the inclusion of DERMS considerations in the SIOWG. This discussion should begin by determining which grid services and use cases where DERMS is truly needed to operationalize DERs. As raised by The Utility Reform Network ("TURN"), the underlying assumption that grid modernization and extensive DERMS systems are necessary to incorporate high levels of DERs should be challenged. While CESA believes that advanced DER functionality and market integration will likely require grid modernization efforts, the cost considerations, grid needs, and tradeoffs should be carefully considered. Additionally, considering the concerns surrounding rising electricity rates for customers, third-party solutions and investments should be leveraged as much as possible. DER providers are already bringing customer solutions to market to enable DER management that is beneficial to the grid, particularly when customers benefit by doing so (e.g. bill or demand charge management). However, as TURN highlights in comments, the Commission should provide direction to "give the private market the opportunity to deploy technology that provides grid services to the benefit of all ratepayers."[20] While utility control and operationalization of DERs will be an important piece of a high-DER future, as summarized by TURN, "A key issue for the Commission to resolve […] is whether such spending for utilities to 'control' all DERs is a cost-effective means to capture the benefits of third party products and services, rather than removing barriers to their use without full utility control."[21]

Question 6: What other specific scoping issues related to smart inverter operationalization should the SIO working group make recommendations on?

CESA has no comment at this time.

Question 7: Currently, the Commission reviews and approves IOU grid modernization plans and associated cost recovery in IOU GRCs. Should the Commission consider in this proceeding whether to move review of IOU grid modernization plans and associated cost recovery out of GRCs and into more dedicated procedural forums?

GRCs are the most appropriate places to discuss specific investments to be made by utilities and associated cost recovery. However, there are many policy and technical capability questions raised by the GMPs that could be addressed in this proceeding, allowing stakeholders to engage more effectively than in the GRC. Decisions about the assumptions of the utilities ten-year planning horizons, underlying forecasts, policy drivers, potential distribution markets, and other changes all heavily influence GMPs but do not involve specific cost-recovery mechanisms. Broader discussions surrounding technical challenges such as cybersecurity and other technical

[20] TURN Comments at 3.
[21] TURN Comments at 3.

needs can also be had in this proceeding or other technical forums, with specific investments being brought forward later in the GRC.

VI. CONCLUSION.

CESA appreciates the opportunity to submit these reply comments on the OIR and looks forward to working with the Commission and other stakeholders in this proceeding.

Respectfully submitted,

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Date: October 7, 2021