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To: Ashkan Nassiri, LADWP (Ashkan.Nassiri@ladwp.com)
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Subject: CESA's informal comments on the revised LA100 assumptions

Re: CESA's informal comments on the LA100 Revised Assumptions Document and the preliminary results' presentations

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Dear LADWP and NREL Modeling Team:

The California Energy Storage Alliance (CESA) deeply appreciates the chance to participate in the LA100 Advisory Group (AG) in order to provide constructive feedback and ensure that the LADWP is successful in its ambitious plans to thoroughly transform its electric sector. Once again, CESA would like to congratulate LADWP and NREL in the monumental modeling effort they have undertaken. CESA has been impressed with its thoroughness and attention to detail. Given the structure of the AG meetings, CESA believes the submission of written informal comments on both the Revised Assumptions Document and the initial results' presentations would be valuable for the LA100 team.

For this reason, CESA submits these written informal comments which may better convey feedback from the energy storage industry perspective. CESA believes that collaboration and communication among all stakeholders can significantly improve NREL's proposed analysis and deliver more robust and reliable results by properly representing the capabilities and benefits of various resource classes for the achievement of Los Angeles' energy and environmental goals.

Our informal comments below are structured to focus on various different aspects of the LA100 Assumptions Document.

Introduction

CESA commends LADWP and the NREL modeling team for taking on such an ambitious and comprehensive modeling effort to assess how the City will achieve its decarbonization goals. CESA is pleased to see the LA100 modeling efforts have yielded results showing that decarbonization requires an aggressive deployment of clean renewable energy and energy storage resources, even after initial runs based on moderate loads and a single weather year. Overall, CESA is supportive of the LA100 modeling efforts. In our comments below, we elaborate on our specific feedback and offer some areas of recommendation for consideration by the NREL modeling team and LADWP staff. Our comments can be summarized as follows:

- Since EVI-Pro is a cost-minimization model that may overlook the potential to develop grid-responsive higher-capacity chargers, NREL should incorporate smart EV charging in the demand response (DR) assumptions to demonstrate this additional value add.

- DR assumptions are a welcome addition to the LA100 modeling efforts, but they should differentiate use limitations and economic dispatch based on technology-specific capabilities and costs.

- Distribution analysis results will be more informative when BTM storage is incorporated and upgrade deferral value is optimized.

- Multi-day and seasonal storage optimization and storage cost technology assumptions should be provided to help us provide more detailed feedback.

- Distributed generation adoption modeling should incorporate available storage-related incentives but BTM storage should also be included in the bulk capacity expansion modeling.

- Production cost and power flow modeling of the LA Leads scenario will inform no-regrets investments, such as for longer-duration storage systems.

We look forward to continuously engaging in the LA100 AG and welcome any questions you may have regarding any of our points below.

<u>Electric Vehicle (EV) & Transportation Load</u>

CESA generally supports NREL's approach to leveraging the EVI-Pro methodology to estimate EV charging infrastructure requirements by location. However, CESA remains concerned with how the EVI-Pro model would select the necessary infrastructure investments. As CESA understands it, EVI-Pro is a cost-minimization model that selects EV charger type (*e.g.*, Level 1 versus Level 2 versus fast chargers) based on driver travel needs and technical capabilities of a charger to meet the driver's energy requirements.[1] This may be a critical oversight around the value of higher capacity EV chargers since they are able to offset the higher incremental costs with additional grid-service revenue while providing additional flexibility and potential resiliency to the grid at large. Furthermore, it is essential to note that L2 chargers are able to charge EVs in a shorter period of time, thus allowing them to remain fully charge and available for marginal

[1] Bedir, Abdulkadir, Noel Crisostomo, Jennifer Allen, Eric Wood, and Clément Rames. 2018. *California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025*. California Energy Commission. Publication Number: CEC-600-2018-001 at 6. https://www.nrel.gov/docs/fy18osti/70893.pdf

dispatch if local frequency or voltage support is needed. Additionally, a potential modeling of EV load as unified and optimizable within the Resource Planning Model (RPM) could enable the collective use of these assets to provide substantial shifting with minimal impacts at the EV level.

The Revised Assumptions Document also details the following: *"The study does consider variations on charging availability at home and workplaces and allows flexible charging as a source of demand response to better align charging with renewable energy supply."*

CESA seeks clarification on whether this "DR service" will come in the form of mid-day load build or as a potential peak shedding DR service. Furthermore, the interaction of residential and commercial customer charging with BTM onsite batteries and co-located rooftop PV should be elaborated. Specifically, it is unclear on how dGen will trigger customer uptake given these additional EV charging loads. This interaction is also a general observation related to residential and commercial building loads, where building electrification may impact solar and storage adoption, even as BTM DERs can reshape loads and provide dispatchable services in line with planning and grid needs.

Additionally, though "vehicle to grid" (V2G) applications are currently excluded from the LA100 analysis,[2] CESA believes that the consideration of delayed EV charging in the demand response (DR) section is definitely an incremental step in the right direction.[3] In interpreting the results, LADWP should view the selection of BTM energy storage resources as reasonable proxies at this time and explore V2G resources in practice through pilot projects and as potentially contractable grid assets. In the future, V2G resources should be considered as candidate resources as well.

Demand Response (DR)

With the addition of DR assumptions in the Revised Assumptions Document and to the modeling efforts, the LA100 Initiative is greatly improved and more broadly captures the available resources that can provide grid services and benefits via flexible loads. The 2025 California Demand Response Potential Study and the Demand Response 2014 Strategic Implementation Plan (SIP) represent robust sources of data on 'Shed' and 'Shift' DR resources for goals established by LADWP and potential opportunities to go beyond those goals.[4] In particular, CESA commends both LADWP and NREL for its endogenous modeling of DR dispatch within the RPM as modifiable load shapes. By allowing for the "supply-side" selection of DR resources in RPM, LADWP will be informed of the cost-effective opportunities to go beyond the 2014 SIP to provide grid services.

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[2] Revised Assumptions Document at 12.

[3] *Ibid* at 18.

[4] The Bring Your Own Device (BYOD) Program appears to only be offered for modernized DR-enabled appliances. This may be a function of an existing DR program from LADWP, which is used to inform this planning effort, but CESA notes that BYOD programs can also be expanded to support PV and/or storage. Green Mountain Power (GMP) in Vermont, for example, has offered a similar program. Where possible, the scope of the BYOD Program should also cover PV and storage.

Especially when in-basin capacity is needed to mitigate risks of longer-duration generation and transmission outages, DR resources can help lower the need for greater amounts of in-basin generation and storage. Furthermore, with high end-use electrification goals, the amount of flexible load capacity is greater.

Among DR loads, however, storage-backed DR should be more accurately represented to represent their costs and capabilities. For example, while the team is considering designating a $10,000/MWh strike price for DR to limit the 'dispatch' of the resource, such economic dispatch behavior is more representative of emergency DR programs that only offer load reductions on a contingency basis with limited calls per season or year. Storage-backed DR and likely some other DR resources are capable of more frequent dispatch as economic, not emergency, resources that could have a strike price in RPM represented at a much lower number (*e.g.*, $300/MWh). Furthermore, depending on the resource, there may be different use limitations on the DR resource than the one assumed for all DR resources (*i.e.*, up to 48 hours of interruptible load per customer per year, at most four hours per day).[5] Storage-backed DR faces more limited customer attrition effects such that more frequent dispatch is possible.[6] NREL should look to add more granularity to the DR resources that can be selected in RPM to reflect these different performance characteristics by technology. The Final Assumptions Document should explain the resource costs that will be assumed and how the multiple-use benefits and use limitations of BTM resources will be considered and counted.

Furthermore, CESA is supportive of the inclusion of EV charging load as shiftable DR loads that can support the City's transportation electrification goals. In the Revised Assumptions document, NREL explains that L2 charging will be incented at higher levels than L1 charging due to its associated grid benefits.[7] CESA believes this distinction is well asserted, as it will create a positive feedback loop between increased electrification and operational flexibility. Nevertheless, CESA would appreciate further explanation regarding the products and services that can be provided by these assets since vehicle-grid integration (VGI) of these assets can greatly impact their utilization and the resulting cost-benefit ratio of these investments (*e.g.*, offset EV charger infrastructure buildout costs, defer distribution investments).

Finally, various DR resources have the potential to avoid or offset distribution upgrade costs if operationalized as DR, but the Revised Assumptions Document explains that DR resources are not included in distribution planning models. This assumption misses an important value adder for DR resources, which we explore further in the Distribution Analysis section of these comments.

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[5] *Ibid* at 19.

[6] See *Energy Division's Evaluation of Demand Response Auction Mechanism Final Report* published on January 4, 2019. While price and technologies backing performance were redacted, storage resources participating in the CPUC's Demand Response Auction Mechanism, which allows for the economic dispatch of third-party-provided DR integrated in the CAISO market, are likely among the highest scheduled and dispatched resources. BTM storage resources providing local capacity requirements for IOUs were used as a benchmark where BTM storage resources were shown to be frequently dispatched for RA capacity.

[7] Revised Assumptions Document at 19.

Distribution Analysis

CESA commends the NREL team for incorporating a distribution analysis as part of these modeling efforts, which is a complex and tall order. Since actual upgrade costs are not used, realization of upgrade deferral or avoidance is not fully featured, and potential protection investments are not included, CESA has some doubts about the actionability of the distribution analysis. As such, this analysis may be helpful for informational purposes and at least inform LADWP grid planners on how to optimally site DERs and build tools to enable such strategic siting by third-party developers.

Overall, the distribution analysis may be more informative once the final runs are conducted when scenarios with high-load assumptions are modeled and when BTM storage is incorporated in the dGen adoption forecasts.[8] BTM storage has the ability to increase hosting capacity and enable energy shifting, which may defer or avoid the need for distribution upgrades. However, this value may not be captured from dGen that only quantifies storage benefits from the customer perspective (*e.g.*, retail rate management), unless rates are well aligned with system-wide and distribution-grid needs.[9] At this time, it is unclear how non-wires alternatives will be modeled or operated in any distribution upgrade capacity expansion decision, other than on a seemingly case-by-case basis.[10]

Finally, CESA urges the LA100 team to evaluate the resiliency contributions of BTM resources, which could be done by performing distribution level analysis in suboptimal (i.e. non-nominal) conditions. In the context of rising risks associated with wildfires and other natural phenomena, CESA considers this facet of analysis to be essential as to find portfolios that minimize the cost of resilience. In this case, CESA defers to NREL's methodological judgement as to which distribution-level configurations and locations are better for evaluation.

Bulk System Capacity Expansion Modeling

The Revised Assumptions Document details how NREL will use its RPM to provide bulk system capacity expansion in five-year increments based on four representative days representing the different peak load conditions throughout the year. Nevertheless, the Revised

[8] LADWP Initial Run Highlights Presentation at 3.

[9] The Revised Assumptions Document suggests a focus on customer value only based on the following: *"The impact to the distribution grid of behind-the-meter storage is based on value to the customer."*

[10] Revised Assumptions Document at 23 explains that emerging solutions like energy storage will be considered depending on the feeder, scenario, and planned upgrade solution, so it appears that this is an after-the-fact assessment. The criteria in which such non-wires alternatives will be considered should be elaborated. CESA also seeks clarification on how changing rate and service assumptions may align these resources with bulk system needs instead of demand management and end-user efficiency savings, given the following in the Revised Assumptions Document: *"Distribution-connected larger storage systems are assumed to be dispatched as indicated by bulk system simulations."*

Assumptions Document is still not clear regarding how these four representative days are treated within each year modeled by RPM, even as NREL has previously explained that RPM is capable of modeling capacity expansion given an optimization horizon of over 24 hours.[11] Prior to the final run results, a Final Assumptions Document should explain how the RPM model conducts such multi-day optimizations.

CESA is greatly appreciative of NREL's willingness to include a wider selection of storage technologies in their modeling. By incorporating compressed air energy storage (CAES) and pumped hydro storage (PHS), NREL is able to note the inflection points and scenarios that require substantial arbitrage. In particular, CESA appreciates the use of actual long/seasonal duration storage technologies instead of using concentrated solar power (CSP) with 8-hour storage duration as a proxy resource. In the Final Assumptions Document, CESA seeks more information on the types of such long-duration storage technologies to be modeled and incorporated in RPM. We look forward to providing feedback on these additional candidate resource technologies.

Moreover, CESA seeks additional information on how RPM will produce transmission and distribution upgrade costs required to achieve the resulting portfolio mix. For DERs, it may be helpful to account for the buildout costs at the T&D interface, as load shaping could produce cost savings at both or for one of the transmission and distribution levels.

Distributed Generation Adoption

As CESA mentioned in the previously filed comments, the use of dGen as the main model to determine the adoption of distributed energy resources (DERs) presents the challenge of assuming some retail billing structure to determine economic potential.

In this Revised Assumptions Document, NREL proposes using two billing structures to incent, in varying degrees, the deployment of DERs: the 'moderate' case settles exports at wholesale prices while the 'high' case does it at retail levels. While it is reasonable to assume agents will be more prone to adopt DERs when their bill is more substantially reduced, LADWP should, in the long term, strive to provide retail rate structures that more closely mirror dynamic grid conditions (*e.g.*, via time-of-use pricing structures), particularly for customers that have opted to deploy storage assets behind their meter for not only bill savings but also resiliency purposes. This modification will more effectively unlock the support potential of these resources, while providing significant bill reductions to engaged customers.[12]

Additionally, CESA recommends that include incentives available to help offset the costs of DERs, such as the Self-Generation Incentive Program (SGIP) for BTM energy storage, for which LADWP customers are eligible to receive. The incorporation of these mechanisms in the modeling

[11] Mai et al (2013). *Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems*. Publication number: NREL/TP-6A20-56723. https://www.nrel.gov/docs/fy13osti/56723.pdf. At 7.
[12] CESA also has questions related to how grid export capacity will be considered in each scenario since different customer investment decisions could be made depending on what services the resource can provide.

would have a direct impact on expected adoption and may result in increased geographic diversity of assets as adoption is closely correlated with several socioeconomic variables. SGIP funds are also designed to prioritize and incentivize deployment of BTM storage in low-income and disadvantaged community sites, which support LADWP's environmental justice objectives. By incorporating SGIP incentives in the dGen resource uptake model, solar and storage adoption results may show improved results aligned with these equity objectives.

Importantly, CESA is still concerned with the modeling and optimization of BTM storage. NREL states that BTM storage assets have their value determined by customer-perceived benefits, which signals these resources are dispatched exogenously to RPM (*i.e.*, as a fixed shape). CESA believes that this characterization limits the ability for BTM storage to act as supply-side and bulk resources that meet system-wide needs while also mitigating distribution impacts. Given that candidate resources can only be modeled in one of the capacity expansion models, CESA believes it would be beneficial to model storage resources in both RPM and dGen as to avoid categorizing BTM storage as solely a load modifier for customer benefit versus solely as a supply-side resource for system benefit. As CESA understands it, rather than siloing distributed generation adoption and procurement, NREL and LADWP should consider how targeted benefits for utility customers under a more proactive planning approach could maximize existing infrastructure and customer participation with the grid.

Production Cost Modeling (PCM) & Power Flow Analysis

CESA is supportive of the effort to include power flow analysis in the LA100 Initiative and the decision to bookend their study by analyzing the SB100 and LA Leads scenarios. With the LA Leads scenario, in particular, modeling a future in which only emissions-free resources are allowed, the results may show the possibilities to more confidently procure and eventually operate no-regrets technologies such as long-duration storage (LDS) systems. Thus, CESA commends NREL and LADWP for this groundbreaking effort which will certainly enable other stakeholders across California to better understand the operational complexities associated with deep decarbonization. CESA, however, requests further information on the assumptions around primary frequency response (*i.e.*, whether this is optimized or a constraint in the model).

Conclusion

CESA appreciates the opportunity to provide these informal comments and hope these responses are helpful. Please do not hesitate to reach out if you have any follow up questions or would like to discuss further.

Sincerely,

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