November 4, 2019

To: Ashkan Nassiri, LADWP (Ashkan.Nassiri@ladwp.com)
Jacquelin Cochran, NREL (Jaquelin.cochran@NREL.gov)

Subject: LA100 Advisory Group: CESA's informal comments on LA100 assumptions

Re: CESA's informal comments on LA100 Assumptions Document and LA100 Advisory Group meeting presentations

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Dear LADWP and NREL Modeling Team:

We appreciate the continued opportunity to participate in the LA100 Advisory Group (AG). CESA has been impressed with the capabilities and engagement of the National Renewable Energy Laboratory (NREL) modeling team and we look forward to seeing the preliminary modeling results at the upcoming AG meeting in December 2019. In particular, CESA has appreciated the follow-up webinars and circulation of NREL's *Methodology, Data, and Assumptions for Analyzing Pathways to 100% Renewable Electricity* ("Assumptions Document") in August 2019, which provides more detailed insights into the various assumptions, modeling processes, and optimization engines to be used in this effort.

However, throughout our AG participation, CESA has noticed that the structure and format of the AG meetings have made it difficult to dive too much into the weeds and details of the technical assumptions and modeling details. The one-day format and the broad scope of the efforts expand the range of stakeholder types involved and make it difficult for the AG meeting to focus on any particular aspect of the modeling efforts.

For this reason, CESA submits our written informal comments on the Assumptions Document and the AG presentations, which may better convey feedback from the energy storage industry perspective. CESA understands that the LADWP and NREL modeling teams are not formally seeking comments, but we hope that our informal written feedback and recommendations can be strongly considered to reflect our industry expertise as well as our experience in participating in other Integrated Resource Planning (IRP) processes in California. With our recommended changes, CESA believes the modeling results will be more robust and will better reflect the capability of various resources in achieving the City's LA100 goals.

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

General Comments

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 LA100 goals through 2030 and 2045/2050. While supportive of the very granular analysis and the feedback loops created by the different models, CESA is concerned that the entire modeling process may be seeking a level of false precision when LADWP and the City may benefit from certain key and high-level modeling outputs that can inform policy-making to achieve the 2030 goals. For example, CESA is concerned that miscalibration or biases for one assumption or one model may lead to cascading effects that give a sense of comprehensiveness but ultimately present misleading results. In other words, CESA is concerned that this modeling effort is aiming to do too much.

A key effect of doing too much and for creating an extension feedback loop for these models is that this modeling effort may be limited in the different types of sensitivities that can be conducted on any of the agreed-upon scenarios. Sensitivity analyses are critical to assessing various technology, price, and regulatory risk factors, and from our experience, multiple cost sensitivities need to be conducted since these capacity expansion modeling exercises can often "swing" dramatically depending on the cost assumptions used. Without this flexibility to conduct multiple sensitivities, the selection of the default cost assumptions will be critically important even though they are subject to significant uncertainty, especially when looking out through 2030 and 2045.

Furthermore, another concern of doing too much with this modeling effort is that any key change or modification can slow down modeling processing time. CESA, for example, supported the addition of modeling climate change effects as part of the default load forecast, but we were also concerned that this slowed down modeling by six weeks. Given the changing marketplace and policy environment, such changes or modifications may be needed again in the future, but modeling could be continuously delayed with any incremental change. Our recommendation is to avoid an "analysis paralysis" situation.

Overall though, we are supportive of the LA100 modeling efforts. In our comments below, we detail specific areas of feedback and offer some areas of recommendation for consideration by the NREL modeling team and LADWP staff. We look forward to continuously engaging in the LA100 Advisory Group and welcome any questions you may have regarding any of our points below.

Electric Vehicle (EV) & Transportation Load

CESA generally supports NREL's approach to leveraging the EVI-Pro methodology to estimate EV charging infrastructure requirements by location, which appears to account for realworld travel data and customer preferences for charger availability,[1] and to identify uncoordinated charging load profiles to develop "flexibility metrics"[2] – *e.g.*, delayed charging, flexible charging, etc. However, it appears that the Assumptions Document is still lacking in terms of how these metrics will be developed, considering it was recognized that "it is unclear what level of charging flexibility vehicle owners are willing to provide."[3] CESA adds that there are additional challenges in understanding the bounds of the flexible EV load that could be provided (*e.g.*, minimum amount of state of charge to meet driver preferences), which will also depend on whether EV batteries improve and increase in driving range and capacity in the future as well as on the prevalence of workplace and public EV chargers – all of which can increase the amount of flexibility that could be provided.

One area for further consideration is how EV loads can be aggregated and optimized in capacity expansion modeling using Resource Planning Model (RPM), which can inform future rate design aligned with grid needs (*i.e.*, how LADWP would like to shape EV charging load shapes) and support aggregation of EV charging loads for broader grid benefits. Furthermore, 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.[4] However, there may be a critical oversight around the value of higher capacity EV chargers in being able to offset the higher incremental costs with additional grid-service revenue. With the ability to ensure sufficient EV battery state of charge in a shorter time frame, there may be longer dwell times during which an EV charger could provide load shift or flexibility. As a result, it may be helpful to incorporate EV chargers into RPM to uncover this grid-service value. With a pure cost-minimization approach for driver needs, CESA believes that this would bias the model to favoring only Level 1 EV charger deployment when there could be opportunity for cost-effective deployment and utilization of Level 2 or higher EV charger deployment that not only meets minimal driver needs but also create significant windows (*e.g.*, long dwell times) to provide grid service during "idle" or long-dwell hours.

CESA notes that the NREL team is not looking at "vehicle to grid" (V2G) resources at this time where an EV could potentially discharge to support the grid.[5] Understandably, more data and information is needed on how such resources could be modeled in future modeling efforts, but at this time, it will be important for LADWP to view BTM energy storage resources as reasonable proxies for V2G resource need and explore V2G resources in practice through pilot projects, demand response programs, and potentially contractable grid assets.

CESA also highlights that the assumptions included in the EV and Transportation Load section focus mainly on light-duty vehicles, overlooking the impacts of medium- and heavy-duty

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[1] Wood et al (2017). "Regional Charging Infrastructure for Plug-In Electric Vehicles: A Case Study of Massachusetts." NREL Technical Report at 12. https://www.nrel.gov/docs/fy17osti/67436.pdf

[2] Assumptions Document at 11.

[3] *Ibid* at 9.

[4] 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

[5] *Ibid* at 11.

vehicle electrification. As CESA understands it, this decision was mostly driven by the effect such an incorporation would have on the analysis timeframe. While CESA is sympathetic towards this reasoning, it is worth emphasizing that the timeline of EV adoption is fundamental when modeling capacity expansion within a system. Thus, CESA recommends LADWP to include a timeline regarding the electrification of buses, the sole medium-duty vehicles considered in the study, in order to have a better understanding of the impacts this category will have on system-wide load.

Finally, CESA finds the "High Stress" assumptions to provide little insight into the workings of EV charging. Based on the Assumptions Document it appears that the sole difference between this scenario and the rest is the limited availability of workplace charging paired with an almost complete availability of residential charging (90%). CESA believes this scenario does not reflect the conditions under which massive light-duty transportation electrification will take place since investment in charging infrastructure that can operate during the daytime will be a key component of said transition. Therefore, CESA thinks this scenario is not constructed in a way that aligns with the goal of electrification. Nevertheless, CESA realizes the purpose of this assumption is to build upon a scenario that would simulate a resource-constricted grid. Furthermore, there appears to be limited to no assessment of required infrastructure upgrades that may be deferred or avoided through smart planning processes that align with RPM identified needs and optimized coordination to ensure limited traditional upgrades are needed to facilitate growth in transportation.

Residential, Commercial, & Industrial Loads

CESA does not have too much to add to these sections. In general, it appears that the assumptions are reasonable, but it would be helpful to clarify how economic adoption of distributed solar and storage via dGen are differentiated or overlap with Title 24 code compliance assumptions. We assume that any mandated solar (in additional to storage as a compliance option) deployed for meeting Title 24 requirements are separate from the dGen optimization since these are required to achieve the zero net-energy requirements as opposed to being optimized for customer return on investments and bill savings. Specifically, it would be helpful to clarify how electrified load feed into the demand response assumptions and modeling since there is potential for flexibility to be provided by various end-use loads, such as from battery storage, smart controlled electric water heaters, and other thermal storage systems.

Demand Response (DR)

CESA finds the lack of assumptions developed for demand response to be a critical gap in the current modeling efforts. CESA understands that the modeling team is working on these assumptions, but this aspect of the modeling process is an important element for each of our recommendations herein on how distributed energy resources (DERs) can support the grid and even offset the need for certain distribution infrastructure investments, particularly as space constraints is a key consideration for resource planning in Los Angeles.

CESA recommends that the NREL modeling team assess the methodology and models used by the Lawrence Berkeley National Laboratory (LBNL), which conducted a DR potential study and identified four products that could be provided from DR resources (Shed, Shift, Shimmy, and Shape).[6] In addition, the LBNL team built "DR supply curves" that incorporated the capital and O&M costs for different end-use loads that could be deployed for providing different types of load services. This may be a starting point for building out the DR assumptions for this modeling effort, but the LBNL methodology may need to be modified and adapted to the LA100 modeling efforts given that the NREL team plans to conduct more agent-based modeling for load and DER forecasts. By contrast, the LBNL team did not incorporate such levels of granularity as they assessed system-level potential for various DR services.

CESA believes the LBNL model provides a good starting point for the development of a bottom-up model that bases its assumptions and processes on actual customer data. Specifically, NREL should evaluate the propensity score for expected DR adoption considered in LBNL's model.[7] This module of LBNL's model estimates the likelihood of customers to adopt DR using statistical methods that combine current DR adoption rates, demographic factors, incentives, and marketing. CESA considers it could prove particularly useful to NREL's agent-based optimization goals. The consideration of this methodology, or at the very least its results, can be helpful for NREL when considering which factors lead to adoption and attrition, as well as determining the cost-benefit ratio of different enrollment tactics by customer.

In building DR supply curves, the NREL team could look at various program offerings in California to establish operational parameters (*e.g.*, event call limitations) as well as net costs that would lead to their adoption. At the same time, CESA recommends that BTM energy storage be optimized outside of the DR model used because storage resources do not face customer attrition issues given that they are 10+ year investments and do not face customer fatigue issues since storage loads are separated from onsite customer load. In addition, unlike end-use load, storage can provide benefits to the distribution system. While BTM storage may participate in DR programs, their resource costs and characteristics are sufficiently different to warrant separate treatment. As discussed further in our comments to the Distribution Analysis section, BTM storage should be separately optimized within the capacity expansion model.

Renewable Resources

CESA seeks further clarification on whether renewable resources can be modeled in hybrid resource configurations. Considering NREL plans to produce hourly or sub-hourly output

[6] See Alstone et al (2017). *2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results*. Lawrence Berkeley National Laboratory. Publication number: LBNL-2001113. http://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf

[7] Ibid, at 3-9 to 3-12.

profiles at each site location,[8] there could be an opportunity for storage resources to be paired with wind and solar resources to take advantage of federal tax credit benefits and cost savings from shared facilities.

Distribution Analysis

CESA commends the NREL team for incorporating a distribution analysis as part of these capacity expansion modeling efforts. We are unaware of any other integrated resource planning efforts elsewhere where such bulk system expansion modeling is combined with an analysis of distribution impacts.[9] However, CESA is unclear on the actionability of the results of the distribution analysis since we presume the actual costs of upgrades will be better determined during interconnection study and application processes as well as part of more detailed distribution planning processes, rather than "approximate electrical models".[10] As such, this distribution analysis should be just informational at this time that only provides some indication of the orders of magnitude of costs to the distribution system.

A potential concern and limitation of the distribution analysis is that the impact of distributed PV (DPV) generation on upgrade costs may be overstated without the incorporation of paired BTM storage in DPV forecasts conducted by dGen. Since dGen is an agent-based model that forecasts both solar and storage adoption based on economic returns to the customer, the underlying retail rates assumed in the model will have a significant impact on not only whether these technologies are adopted but also on how they will operate for grid benefit. For example, if rates are structured to be time-based and dynamic with sufficient differentials that reflect marginal distribution costs, solar-plus-storage resources could have reduced impacts on distribution upgrade costs.

Furthermore, CESA also adds that BTM storage, smart EV charging solutions, and other grid-interactive DERs can serve as alternatives to distribution capacity investments to address increasing load forecasts as well as for hosting capacity expansion investments, where storage operated in a way to charge during solar overgeneration hours could relieve thermal limitations and voltage deviation issues. Distribution solutions such as storage appear to be considered as "emerging solutions"[11] but it is unclear on how such non-wires alternatives will be modeled or operated, as well as how the distribution upgrade capacity expansion decision will be made in the distribution analysis – *i.e.*, how will the economic decision be made for non-wires alternatives versus traditional grid investments. In CESA's experience, the procurement of non-wires alternatives is a very project-specific economic decision, where the costs and deployment timelines play a major factor in their selection. Considering this modeling effort will look at 2030 and 2045, it is also unclear on whether the source data for the planned upgrade costs from

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[8] Assumptions Document at 19.
[9] Hawaiian Electric Company (HECO) is trying to do this, but from our understanding, this type of distribution analysis has faced many challenges.
[10] Assumptions Document at 19-20.
[11] *Ibid* at 20.

LADWP and NREL's Distribution Unit Cost Database can be applied. As CESA understands it, actual planned investment cost data is highly project- and location-specific and includes a number of engineering judgment calls to identify the least-cost solution.

Finally, CESA observes that NREL will not include a centralized distribution operations scheme (*e.g.*, ADMS or DERMS in line with a distribution system operator [DSO] model).[12] While having no issue with this decision given the complexities of modeling DSO-style optimizations, NREL and LADWP should acknowledge that this biases to a degree the resulting portfolio to transmission investments and transmission-connected generation resources. With DSO infrastructure in place, for example, there could be significant potential to mitigate distribution costs for DERs operating to defer investments and take advantage of hosting capacity and/or increase hosting capacity.

CESA welcomes this innovative approach to comprehensively assess upgrade costs related to load and DER growth, including potential emerging solutions. However, CESA is concerned that this distribution analysis may be attempting to do too much with questionable results on upgrade costs as well as potential complexities in trying to model non-wires alternatives in addressing distribution capacity needs. Instead, CESA believes a more simplified approach could be pursued where DERs are selected and optimized in capacity expansion modeling, which can also inform smart rate design and potential grid-service contracting opportunities to achieve the intended grid-beneficial behavior. Furthermore, alternative scenario assessments should be considered to adjust customer/feeder load shapes based on identified future needs. Planning often assumes that current load is optimized. The DSO model, with a focus on infrastructure deferral and load shaping, will provide significantly different results and must be assessed in the LA100 Plan.

Bulk System Capacity Expansion Modeling

The 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 Assumptions Document is not clear regarding how these four representative days are treated within each year modeled by RPM. According to NREL, the RPM is capable of modeling capacity expansion given an optimization horizon of over 24 hours; that is, RPM is capable of modeling any number of consecutive days per year.[13] However, the Assumptions Document seems to imply that the modeling for the LA100 project will be done using non-consecutive days. CESA believes this approach could seriously hinder the valuation of storage assets that are able to provide energy arbitrage for days and even weeks at a time. Such resources are especially valuable in a context of high renewable penetration such as the one pursued by the City.

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[12] *Ibid* at 22.

[13] 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.

Considering NREL has previously stated the RPM is capable of performing such optimization, CESA exhorts NREL and the LADWP to consider modeling consecutive days for each of the years considered in the bulk system capacity expansion modeling. This could be done in two different ways: the seasonal approach or the week approach. The seasonal approach would imply the modelling of four consecutive days by season of the year. These four-day blocks would not be consecutive with each other (i.e. the spring days would not feed into the summer days and so on.) These four-day blocks would represent the weather conditions of each of the seasons as well as the low, mid, high, and peak conditions by season. This approach would offer better insights regarding the resource needs by season and their dispatch; however, it could be overly burdensome in terms of modeling time since it would essentially quadruple the number of days modeled by year. The second approach is the week approach. In this approach only seven days are modeled each year, but they are optimized consecutively in order to extract valuable insights regarding the potential needs for multi-day energy arbitrage. Within this approach different weather and load conditions can be considered within the week, as planned by NREL in the Assumptions Document. CESA believes this approach strikes a balance between accuracy and modeling time and hence exhorts NREL to consider it.

In addition to modeling consecutive days, CESA also suggests including a probability of extreme weather events within the modeled days. CESA commends NREL and LADWP for considering the impact of climate change on average temperatures; nonetheless, CESA considers this might not be enough to properly incorporate the risks associated with climate change in the State. The effects of climate change on the likelihood and scale of natural disasters have become overtly apparent in recent days; thus, CESA recommends NREL incorporates a probability within each day modeled for that day to be an "extreme weather event day". This would mean that any day within the selected number of days per would have a non-zero probability of being an "extreme weather event day". CESA defers to NREL's expertise for determining the value of said probability. CESA believes this approach is balanced and beneficial since it does not force an extreme weather event to happen every single year, but it opens the possibility for at least one to be modeled within NREL's analysis.

CESA is supportive of including conventional plant retirement in the RPM capacity expansion modeling using annual capacity factor by technology below which a plant is assumed to retire. This appears to be a reasonable proxy for factors that would drive retirement and eventual replacement by resources such as energy storage, but we recommend that NREL substantiate the capacity factors used because the thresholds cited in the Assumptions Document appear to be too low, in our view. Alternatively, if it would not delay modeling efforts too much, CESA recommends that NREL consider an economic retirement module in the RPM optimization logic by considering the fixed operations and maintenance (O&M) costs of fossil-fueled plants and only retaining these resources, subject to reliability constraints, if it is cost-effective to do so. This approach enables the model to objectively minimize costs and provide a better panorama of future retirements over time.

CESA considers the cost assumptions used by NREL to be generally reasonable and robust given they were derived from a wide survey of both academic and industry sources. Nonetheless, CESA recommends that NREL include a non-zero value for variable O&M for lithium-ion battery storage resources, especially considering energy storage resources will likely be used to perform daily energy arbitrage. Currently, the California Independent System Operator (CAISO) is considering estimating the costs storage resources incur by doing daily, deep cycling. The CAISO considers these costs to be a function of both replacement costs (*i.e.*, the cost of the storage unit) and depth of discharge (DOD).[14] CESA believes that, in general terms, the CAISO methodology is correct and recommends NREL use it solely by replacing the replacement cost assumption with the battery pack costs included in NREL's Annual Technology Baseline data.[15]

NREL also details how "multiple energy storage technologies" will be modeled,[16] but it appears that the range of storage technologies will be limited to four-hour lithium-ion batteries based on NREL's Annual Technology Baseline data. CESA believes this overlooks the broad range of storage technologies (*e.g.*, flow batteries, compressed air energy storage) that may be needed and economic to meet the City's long-term LA100 goals. As the City moves toward a grid mainly served by variable energy resources (VERs), the need for energy arbitrage and output firming will increase. Furthermore, unpredictable natural disasters and/or a series of suboptimal generation days (*e.g.*, cloudy days) could severely hinder reliability in a system based on VER generation. Academic studies on the subject have shown that there are essentially two ways to solve this issue: overbuilding capacity or investing in storage technologies that can provide multi-day arbitrage.[17] In fact, NREL presented on this topic at its June 7, 2018 presentation to the LA100 Advisory group.[18] Without considering the full suite of options available to LADWP, including the various types of energy storage technologies, this modeling effort will not yield a truly optimized portfolio.

Given the locational constraints for considerable capacity overbuilding, CESA urges NREL to consider technologies with durations over four hours. CESA proposes three ways in which this can be done: (1) including a wide array of storage technologies as candidate resources; (2) modeling long-duration storage technologies by proxy; or (3) obtaining optimal duration of storage assets as an output.

The first option implies incorporating several energy storage technologies as candidate resources. These could include flow batteries, pumped hydro storage, storage by hydrolysis, flywheel storage, compressed air energy storage, gravitational storage, thermal storage, among

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[14] Zhang, Yi (2019). *Economic Planning – Production cost model (PCM) development, Renewable Curtailment and price model, and battery cost model*. California Independent System Operator. http://www.caiso.com/Documents/Day1-Presentations-2019-2020TransmissionPlanningProcessMeeting-Sep25-26.pdf. At 253-257.

[15] Specifically, the data included in the "Storage" tab, cells AX10 to CD12.

[16] *Ibid* at 23.

[17] See Becker et al. "Features of a Fully Renewable US Electricity System: Optimized Mixes of Wind and Solar PV and Transmission Grid Extensions." Energy 72 (2014): 443-58; and Budischak et al. "Cost-minimized Combinations of Wind Power, Solar Power and Electrochemical Storage, Powering the Grid up to 99.9% of the Time." Journal of Power Sources 225 (2013): 60-74.

[18] See presentation here: https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB657025&RevisionSelectionMethod=LatestReleased

others. CESA believes this option would be the most adequate as it would represent each technology with its own cost assumptions and operational characteristics and constraints. This process would entail a considerable revision of NREL's Annual Technology Baseline data. CESA has collected and reviewed literature on the best sources for such data and would be happy to share this information if NREL pursues this approach.[19] CESA believes this is the most straightforward approach that would not require significant modifications to the underlying model and would just require robust and publicly available sources for cost and operational assumption data. Given that LADWP is actively considering expanding its pumped hydro assets[20] and is also pursuing a compressed air energy storage project[21] at the Intermountain Power Project, it would be illogical and ultimately yield less-valuable results to exclude these and other energy storage technologies from the model.

The second option, on the other hand, would use only a couple of long-duration technologies to approximate resource need and cost-effectiveness. CESA believes using flow batteries (6- to 8-hour) and pumped hydro (12- to 24-hour) could be a viable alternative. Both these technologies have been deployed commercially and have robust cost estimates available. Modeling by proxy, while incomplete and suboptimal, eases the administrative burden of updating input assumptions.

Finally, the third option would only consider a limited number of energy storage technologies (*e.g.*, lithium-ion, flow batteries) and RPM would select both an optimal amount (MW) and duration of those resources. That is, rather than selecting the optimal level of four-hour lithium-ion battery storage, the RPM model should be able to optimize for the duration of these batteries by reflecting the added energy duration costs. CESA believes that, while this option would be better than the second one, this would likely require a substantial modification of the RPM model.

Finally, CESA recommends that NREL consider modeling BTM storage resources as supply-side resources that can be selected for deployment within the RPM. Currently, the Assumptions Document suggests that BTM resources will be forecasted by the dGen model and considered as

[19] For example, see the following as a good source for data on various storage technologies: Pacific Northwest National Laboratory. "Energy Storage Technology and Cost Characterization Report." July 2018. https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

[20] See SCPPA's *Request for Proposals for Stakeholder & Community Outreach Services Agreement for Boulder Canyon Pumped Storage Project* here: http://scppa.org/file.axd?file=/2019/05/RFP_Stakeholder%20%20Community%20Outreach%20Services%20Agreement%20for%20Boulder%20Canyon%20Pumped%20Storage%20Project_05-09-2019%20to%2006-06-2019.pdf; See also: Penn, Ivan. "The $3 Billion Plan to Turn Hoover Dam Into a Giant Battery." *New York Times*. July 24, 2018. https://www.nytimes.com/interactive/2018/07/24/business/energy-environment/hoover-dam-renewable-energy.html

[21] See SCPPA's *Request for Proposal (RFP) for a Compressed Air Energy Storage Project* here: http://scppa.org/file.axd?file=/2017/11/Compressed%20Air%20Energy%20Storage%20RFP.pdf
See also: Roth, Sammy. "A clean energy breakthrough could be buried deep beneath rural Utah." *Los Angeles Times*. August 8, 2019. https://www.latimes.com/environment/story/2019-08-07/renewable-energy-storage-los-angeles

load modifiers. While CESA understands the merits of NREL's agent-based approach, CESA believes this approach does not accurately represent the effects of BTM resources in the distribution grid. Specifically, CESA thinks the way the dGen and RPM models interact with each other leads to the conclusion that BTM storage resources (both those deployed standalone and those within EVs) solely increase load without providing any other service for the grid, either locally or system-wide. This argument is further developed in the following section.

<u>Distributed Solar & Storage Adoption</u>

As compared to top-down forecasts using econometric methods, CESA sees many advantages to using a bottom-up agent-based model (dGen) that simulates consumer decision-making at a very granular level (*e.g.*, 15-minute resolution) to forecast customer adoption of distributed solar and storage at the building level. In other regulatory and technical venues (as opposed to disaggregating system-level forecasts), CESA has advocated for assessing economic rates of return to forecast distributed solar and storage adoption and deployment, which better captures potential spatial deployment of customer-sited solar and storage resources. Granted, a challenge of this approach is that the model must assume some retail billing structure to determine economic potential, which NREL proposes to assess based on two scenarios (*e.g.*, net metering, net billing). A similar customer-perspective is implied for estimating the impact of behind-the-meter solar and storage on the distribution grid based on how dGen outputs will be used in the distribution analysis.[22]

Using dGen raises some concerns if the current or alternative rate structures and parameters used are not conducive to DER adoption. The Figure 16 schematic suggests that there could be a rate structure adjustment, but we assume this just entails a change to the scenarios.[23] Furthermore, the model should take into account any 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.

Importantly, CESA raises questions around how BTM storage is modeled since it is not addressed in detail and the modeling process flow suggested between the dGen and RPM models suggest that DERs like energy storage may be limited in its ability to act as supply-side and bulk resources that meet system-wide needs while also mitigating distribution impacts. For example, while the Assumptions Document suggests that there will be a ranking of sites based on interconnection costs for distributed PV deployment, it does not appear to contemplate how storage could be added to mitigate hosting capacity constraints. To address this, CESA recommends that NREL model BTM storage as a discrete resource that can be optimized in capacity expansion modeling. The adoption of distributed storage for grid-service benefit can be based on the combined economic value to the customer and to LADWP, which should trickle

[22] *Ibid* at 22.
[23] *Ibid* at 29.

down to customers anyway. This could inform future rate design as well as new grid-service programs and solicitations.

As CESA understands the proposed modeling scheme, candidate resources can only be modeled in one of the capacity expansion models, RPM or dGen. If this is the case, CESA believes it would be beneficial to model storage resources within RPM rather than dGen, as mentioned previously. This would avoid categorizing BTM storage as solely a load modifier and instead it would accurately assess its value by mitigating capacity constraints and providing deferral opportunities.

Furthermore, instead of upgrading T&D infrastructure for PV and EV loads, the study should look at the planning benefits of how customer-certified operational controls can be coordinated to avoid forecasted traditional utility infrastructure upgrades for PV and EV. We recommend two additional modeling scenarios to compare impacts of a hosting capacity expansion approach (PV & EV infrastructure deferral) on the High Distributed Energy and High Load Stress (with high DG adoption and not Balanced).

<u>Production Cost Modeling (PCM) & Power Flow Analysis</u>

CESA is generally supportive of the PCM assumptions[24] and power flow analysis (using PSLF), particularly in leveraging this step as a validation for the capacity expansion portfolios, including for sub-hourly operations. However, some additional documentation should be provided on how different technologies will be modeled in PCM since this could drive the results on whether a given portfolio is reliable. For example, in other IRP efforts, CESA has found that the assumptions for renewable curtailment and storage operations and O&M costs as driving vastly different results. For each of the reliability criteria, it is unclear on how different technologies can address different reliability needs. In addition, CESA also requests that modeling outputs using the RA tool (using PRAS) be provided on month-by-month basis, if possible, to inform key resource planning gaps and decisions.

<u>Air Quality & Public Health</u>

CESA supports NREL's three proposed scenarios that provide comparability and can provide insights into the effect of electrification.

<u>Environmental Justice</u>

[24] *Ibid* at 32-35.

CESA supports NREL's plans to model tract-level environmental justice impacts for rooftop solar, energy efficiency, and EV charging infrastructure. CESA is particularly interested to see how the location of DER deployment might impact the dispatch of fossil-fueled resources at various locations given the grid architecture and granular load needs, which has environmental justice impacts. CESA hypothesizes that DER deployment at the site of environmental justice communities would mitigate the emission of localized pollutants and the need for local fossil-fueled resources, but that may not necessarily be the case. If DERs can be deployed outside of environmental justice communities while still reducing local dispatch of fossil-fueled resources, this would support policymaking to not only focus on DER deployment in environmental justice communities to achieve these goals.

Climate Change Impacts

CESA supports NREL in responding to AG member feedback in incorporating climate change impacts on building load forecasts. At first, CESA was concerned that accommodating this request would lead to "scope creep" and lead to the model attempting to account for too much, especially as more modeling parameters come with tradeoffs in increased model run time and reduced ability to conduct sensitivity analyses. However, it appears that the NREL team's proposed modeling of increased building load impacts are a reasonable assumption for default future load forecasts. While not complete in accounting for all climate impacts, focusing on this aspect strikes the appropriate balance.

To the degree that hydro resources play a significant role in different LA100 futures, it may be worthwhile to assess the climate impacts on precipitation on hydro availability in a sensitivity analysis. If the results bear this out, then it may be prudent to assess such risk factors. Furthermore, CESA sees value in future modeling of climate change impacts more broadly, not just on cooling load impacts but also on generation availability (*e.g.*, renewable generation, hydro) and reliability standards (*e.g.*, 1-in-10 versus 1-in-2 standards). Especially since sampling approaches to model a few time slices or representative days per year can omit effects related to more extreme weather conditions, modeling of climate change impacts more broadly can capture the value of identifying the optimal resource mix that provides resiliency and reliability in contingency and critical peak conditions. As mentioned in previous comments, this can be incorporated as a non-zero probability within all days modeled by the RPM.

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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