The CAISO received 5 sets of comments on the topics discussed at the April 13 stakeholder call and 3 sets of comments were submitted into the CPUC process. CAISO encourages all market participants to submit comments within the CAISO process.

1. Smart Wires
2. Calpine
3. Middle River Power LLC
4. Vistra Energy
5. San Diego Gas & Electric (SDG&E)
6. Protect Our Communities Foundation (POC)
7. Center for Community Energy (CCE)
8. Pacific Gas & Electric (PG&E)

Copies of the comments submitted are located on the Local capacity requirements process webpage at:

http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx

The following are the ISO's responses to the comments.

1. Smart Wires Submitted by: Chris Ariante		
No	**Comment Submitted**	**CAISO Response**
1a	Smart Wires requests that the CAISO re-evaluate the Tesla – Delta Switchyard 230 kV line reactance project (“Project”) should the Greater Bay Area (GBA) Local Capacity Requirement (LCR) be revised and reduced via a solution provided by PG&E. Given the CAISO’s response to PG&E’s comments posted on April 9th 2020, it is Smart Wires’ understanding that the CAISO will continue to work with PG&E to explore options to reduce the GBA requirement as noted below: “The CAISO will continue to work with PG&E planning and operations departments to explore options that can be implemented such that within 30 minutes after the loss of the transformer bank, the flows from Metcalf are diverted to other 500/230 kV stations serving the Bay Area in a manner that will result in reduction of local capacity requirement. PG&E should move forward expeditiously with rerates for the Metcalf 500/230 kV transformer banks if technical data supports such an action.” In addition, the CAISO’s response to Smart Wires’ most recent set of comments also included that the Telsa – Delta line reactance project: “can be reassessed if the requirement for the overall Greater Bay Area is reduced such that the Contra Costa sub-area local resources are not required towards satisfying the overall Greater Bay Area requirement.” Smart Wires interprets CAISO’s comments to indicate that if GBA LCR is reduced, the Project may provide material benefit. Therefore, Smart Wires is submitting these comments to encourage the CAISO to re-evaluate the Project if the GBA LCR requirement is reduced pending further discussions with PG&E. As stated in our earlier comments, if the CAISO finds the Benefit-Cost Ratio (BCR) of the Project, or a scaled reactance solution as described on Smart Wires March 30 comments, to be favorable, Smart Wires encourages the CAISO to approve the project and include the reduced LCR need for the Contra Costa Sub-Area in the Final May 1 LCR Study Report submitted to the CPUC. Smart Wires appreciates this opportunity to comment and commends the CAISO for its continued engagement with stakeholders as we strive to find the most cost-effective solution to meeting LCR needs.	The Project will be reevaluated at a later date after the Bay Area overall requirements have been successfully reduced.

2. Calpine
Submitted by: Mark J Smith

No	Comment Submitted	CAISO Response
2a	Calpine supports the LCR Technical Report and specifically, the inclusion of all of the contingencies considered in TPP. Calpine's recommendation, which was adopted in this study scope and technical report, was as follows:	Thank you for your support.
	"Calpine suggests that the scope be revised to ensure that the Local Capacity Technical studies address the same set of contingencies as those required under the revised NERC Transmission Planning (including TPL-001-4) standards."	The current LCR studies comply with all mandatory standards including TPL-001-4.
	This allows LCR studies, transmission planning and resource development to equally consider all constraints on the grid. This change now appropriately includes less common, but significant contingencies (such as T-1-1 contingencies addressed by PG&E in comments) that must be managed within the 30-minute emergency response time required by reliability standards.	
	Additionally, the Technical Report beneficially includes an analysis of storage/charging limits for certain of the local areas and sub-areas. These initial findings are striking, in that it appears there may already be more storage (in terms of capacity) approved and under construction in some areas than can be recharged given the combination of import limits and load shapes. Additionally, it appears that the storage being developed does not have sufficient discharge duration to meet the load duration. (See generally the results for South Bay/Moss Landing).	Thank you for your support.
	Calpine has reviewed the conclusory information provided by the CAISO, but has several questions about the inputs, calculations and results of the storage analysis. We ask that in the 2020/21 LCR Studies, the CAISO provide the models, spreadsheets and input variables used to perform this analysis.	The CAISO utilized spreadsheets and techniques that were tailored to the different circumstances in the LCR areas. These will continue to evolve and be refined, as the storage charging estimates are informational only, considered preliminary, and will be refined in subsequent studies. Accordingly, it is premature to be providing these materials at this time and the ISO will consider the issue in the future.

3. Middle River Power LLC
Submitted by: Jeff Malone

No	Comment Submitted	CAISO Response
3a	Dear California ISO Regional Transmission, In your April 13, 2020 Presentation for the 2021 & 2025 Final LCR Study Results, Slide 11 Border Sub area Daily Load Profiles and L-1 Load Serving Capability 2021 (see attached) is depicting the incorrect information for the El Cajon Sub area instead of the Border Sub area. Can you please provide me with the correct chart for the Border Sub area for 2021?	The CAISO has included the correct information in the draft 2021 as well as the final 2021 LCR reports. Corrected information has been provided.

4. Vistra Energy Submitted by: Amanda Frazier		
No	**Comment Submitted**	**CAISO Response**
4a	Dear CAISO staff: We have reviewed the presentations and draft reports related to your 2021 and 2025 local capacity technical study results, and had outstanding questions, that we hope you will answer: Our questions relate to the figures in each of the reports and presentation on the South Bay-Moss Landing Sub-Area that reflect the approximate amount of storage that can be added to each sub-area from a charging restriction perspective. In the Presentation, this is located on slide 16. In the 2021 report (Figure 1.6-39), this is located on p. 76 and in the 2025 report (Figure 3.2-31), this is located on p. 64. First, there is a discrepancy with respect to how much storage can be added between the figure in the 2025 report (400 MW and 4400 MWh) and the presentation for the 2025 study (0 MW and 0 MWh). Can you please tell us which is correct, and if the report has been updated, explain why? Second, and more generally, we are not sure how to interpret the figures, to derive the outcome that you calculated, so we would appreciate the underlying calculation and/or methodology for how you determined the energy storage amounts (both MW and MWh). Thanks in advance for your attention to these questions. Please contact me if I can provide any additional information or clarification.	A 400 MW battery with 4400 MWh discharge capability can displace about the same amount of local gas resources. Currently there are plans for the installation of 558 MW of 4 hour batteries, therefore 0 MW can be installed above that amount and provide LCR benefit. Please see the response to 2a above.

5. San Diego Gas & Electric (SDG&E)
Submitted by: Nuo Tang

No	Comment Submitted	CAISO Response
5a	SDG&E appreciates the opportunity to comment on the CAISO's Final 2021 Local Capacity Technical Study. During the April 13, 2020 stakeholder meeting, the CAISO indicated that it performed a preliminary study in the LA Basin and San Diego-Imperial Valley ("SD-IV") areas to better understand the potential storage charging capability under a specific scenario in which a critical contingency lasts more than a single day and there is no local gas generation capacity available. SDG&E appreciates this type of study and would like to better understand the results based on the CAISO's responses to the following questions in the final LCR study. The preliminary results of the SD-IV area show a hypothetical scenario where the transmission system is upgraded or some portion of local gas generation is retained to provide up to 3600 MW of load serving capability under the critical contingency condition. This is increased from 2500 MW of load serving capability if the transmission system is not upgraded and there are no location gas generation. 1. What is the minimum amount of local gas generation that must be retained without upgrading the transmission network in order to achieve 3600 MW of load serving capability? 2. The need for retaining gas generation or upgrading the transmission system is dependent on the load forecast. Does the CAISO conduct sensitivity analysis for high load forecast under electrification scenario? 3. Are there other solutions to resolving this issue without the need to retain gas generation or upgrading the transmission network such as co-located storage? 4. How does the CAISO plan to use these results in the transmission planning process or the CPUC's Integrated Resource Plan proceeding? 5. If insufficient gas generation is retained and the transmission system is insufficiently upgraded, does this impact the deliverability of resources or eliminate the ability for storage resources to count towards providing Local resource adequacy? 6. Does this study incorporate other studies performed by the CAISO related to the LCR and use-limited resources? Specifically, in a scenario where	1. The 3600 MW of load serving capability is made up from the existing transmission capability of 2500 MW plus a minimum of 1100 MW of existing local resources. 2. At this time the CAISO only has results for the CEC approved load forecast. 3. The same load serving capability can be achieved with gas-fired resources or resources with similar characteristics. 4. Currently the results are advisory. 5. This study assumes that enough gas resources are retained until transmission upgrades or other resources with similar characteristics can be made available. 6. This study is intended to identify the battery characteristics required in order to seamlessly integrate and reduce the need

No	Comment Submitted	CAISO Response
	certain gas generation is retained but are use-limited resources, does this impact the load serving capability to charge the storage devices? Thank you.	for some of the existing gas resources. Please read section 2.4 of the final 2021 LCR report.

6. Protect Our Communities Foundation (POC) Submitted by: Tyson Siegele		
No	**Comment Submitted**	**CAISO Response**
6a	The Protect Our Communities Foundation ("POC") submits these comments in accordance with Administrative Law Judge Chiv's April 2, 2020 E-Mail Ruling Modifying Track 2 Schedule For Local Capacity Requirement And Flexible Capacity Requirement Issues. CAISO provided its Draft Local Capacity Technical Analysis for 2021 ("Draft LCR Report") on April 2, 2020 for parties' comments. **Introduction** POC appreciates the work completed by the CAISO on the Draft LCR Report. While many elements of the draft provided reasonable and accurate analysis of the local capacity areas, POC focuses its comments on points of concern and inaccuracies found within the draft. Specifically, POC found inaccuracies with the San Diego – Imperial Valley LCR, which should be corrected before the release of the final draft. Additionally, the CAISO LCR report lacks transparency, making determinations regarding the CAISO's assertions of transmission need and projections of demand difficult to evaluate. Based on the statements made by CAISO in the Draft LCR Report, POC recommends: 1) decreasing the multi-layered web of reliability metrics applied to the CAISO service territory; 2) simplifying the LCR demand projections and removing participating transmission operators' ("PTO") involvement in demand projections; and 3) correcting the San Diego – Imperial Valley Area demand projections to align with historical peak demand and historical peak time of day. Once CAISO makes these corrections, the system will maintain reliability while reducing costs to ratepayers.	See comments responding to each detailed point below.
6b	**The Reliability Standards Used By The California Independent System Operator ("CAISO") In Determining LCR Fail To Adhere To The Statutory Standards That The Commission Must Follow.** The Public Utilities Code requires the Commission to "minimize impacts on ratepayers' bills." Thus the Commission must consider costs to ratepayers when evaluating whether to agree with CAISO analyses. Over the years, CAISO's analyses and reliability standards have led to excessively high transmission rates. To illustrate how large transmission costs have grown in California as a result of CAISO's reliability policies, in SDG&E service territory	The transmission costs in POCs comments are not consistent with the transmission costs posted on the CAISO web site. http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveFeb29_2020_Revised_Apr10_2020.pdf

No	Comment Submitted	CAISO Response
	transmission costs have increased to 4.8 cents per kWh. Meanwhile, for the average U.S. investor-owned utility, the average transmission, distribution, and administrative costs combined are less than 4-cents/kWh. CAISO's standards have resulted in a process of gold-plating the transmission system by, adhering to the most conservative criteria at every turn and by layering several reliability standards on top of each other. The Draft LCR Report states that "grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC") Regional Criteria." As noted in the Draft LCR Report, California law requires CAISO to follow the both sets of standards. CAISO refers to the WECC and NERC standards collectively as "Reliability Standards." Two overlapping sets of reliability standards – NERC and WECC - should provide enough redundancy to ensure reliability. However, in addition to the Reliability Standards, CAISO goes further and lays out even more stringent standards in its "Applicable Reliability Criteria" defined as "the Reliability Standards as well as reliability criteria adopted by the CAISO." The CAISO does not need a third set of standards. CAISO should immediately eliminate the additional reliability standards that it imposes, which exceed the two regional reliability standards. Just as the Commission must minimize impacts on ratepayer bills, CAISO should also minimize costs to the ratepayer rather than continue with a set of standards which have resulted in some of the highest transmission costs in the country.	The HV TAC Rate in SDG&E is approximately 1.2 cents per kWh and the LV TRR in SDG&E is approximately 1.8 cents/kWH. Combining these two amounts represents a transmission rate of approximately 3.0 cents per kWh in the SDG&E service territory. The basis for the CAISO standards to address issues not already addressed in NERC and WECC standards was set out in legislation, and the standards are approved by the CAISO Board and enforced through the CAISO Tariff approved by FERC. The CAISO maintains that its standards are necessary and required in order to reliably operate the CAISO grid. The CAISO is committed on minimized ratepayer costs within the bounds of all mandatory reliability standards.
6c	**CAISO must make the demand projections for LCRs more transparent and less dependent on PTO input.** According to the Draft LCR Report, CAISO determines the system load forecast by taking the California Energy Commission forecast and distributing it "across the entire system, down to the local area, division and substation level. The PTOs use an econometric equation to forecast the system load." Thus, the forecasts involve at least three different entities' input. With so many parties involved, and so many steps, the parties forecasting load levels have too many opportunities for mistakes. Once a mistake enters the forecast it can replicate and possibly amplify through the various steps, leading to excessively skewed results at the end of the process. Mistakes will lead to projections which do not	The CEC only forecasts the load at a macro level, primarily at the system and Participating Transmission Owner service territory level. The current process requires an entity to translate that down to individual buses (tens and hundreds across the system). The Participating Transmission Owner is the entity that has access to this detailed data and can do the split to each individual bus. At this time the CEC forecast does not have enough detailed information to be able to distribute to each individual bus bar modeled across the system. This is the process agreed upon by all agencies (CEC, CPUC and CAISO)

No	Comment Submitted	CAISO Response
	reflect reality. Additionally, the inclusion of PTOs in the process fails from a neutrality perspective. PTOs have a vested interest in maximizing the value of their transmission assets and thus increasing the demand forecast. PTOs should be removed from the LCR demand projection process to remove the inherent conflict of interest. The CAISO should streamline demand projections and eliminate parties that have a conflict of interest from directly influencing the process. By adopting POC's recommended changes to the CAISO's peak demand forecasting process, the CAISO may eliminate avoidable errors in the future. POC details its specific concerns with the CAISO LCR analysis in the following section.	on how load forecast is allocated to individual buses and how all technical planning studies are performed. The CAISO checks to make sure the load forecast is reasonable before commencing the studies.
6d	**CAISO must correct the San Diego – Imperial Valley Area load projections which are too high and are wrongly assumed to be later in the day.** The CAISO demand forecast for the San Diego – Imperial Valley Area incorrectly shifts peak demand two hours later in the day than has historically occurred and assumes higher MWs of peak demand than historical trends support. Both of CAISO's alleged future demand shifts – higher demand, later in the day - lack supporting data and will lead to higher ratepayer costs due to the resulting over-procurement. **A. The CAISO projections must be revised to demonstrate an alignment with historical trends.** The load forecast for the San Diego – Imperial Valley Area does not adhere to the declining historical trend of energy demand in the LCR. Figure 1 below shows the decreasing trend in peak electricity demand for the San Diego Gas and Electric ("SDG&E") service territory. Figure 1 shows that the peak load trends down in each year except in the 2016 outlier year, which exhibited an even lower demand. The demonstrated historical reduction in peak demand mirrors the BTM solar installations in SDG&E service territory. From the end of 2015 to the end of 2019, 752 MW of BTM solar was installed in SDG&E service territory. From 2015 to 2019, the peak demand in SDG&E territory fell 655 MW. Further, the pace of BTM solar installations in the region continue growing. 2019 saw the highest BTM solar installations to date at 215 MW. Because solar contributes electricity to either serve supply at peak times (utility scale) or decrease net load at peak times (BTM), the San Diego – Imperial Valley Area will continue to see peak demand fall. CAISO's draft report fails to include, much less to analyze the effects of, the	The demand forecast for San Diego-Imperial Valley area comes directly from the approved CEC IEPR forecast, including the magnitude, hourly profile and hour of peak. Comments on load forecast for San Diego-Imperial Valley should be made through the CEC IEPR process. The CEC IEPR process that has been used for these studies has concluded with the resulting load forecast used in the LCR studies as agreed upon by the agencies (CEC, CPUC and the CAISO) as well as stakeholders. The installation of BTM solar resources moves the peak each year to a later and later hour. The CEC has projected that based on expected total BTM solar installation by year 2021 the peak has moved to 8:00 PM and therefore any additional solar BTM will not influence the actual peak.

No	Comment Submitted	CAISO Response
	BTM solar installations that have occurred and that continue to occur in SDG&E service territory. This failure to include or analyze relevant facts should be corrected in the final report. **B. CAISO incorrectly adjusted the time of the peak load to later in the day, and in so doing, removed BTM solar's contribution to the reduction of peak load.** CAISO set the San Diego – Imperial Valley Area peak for 2021 at 8:00 p.m. - much later than other LCRs in Southern California. As a point of comparison, for the adjacent LCR, CAISO set the peak for the LA Basin LCR Area at 5:00 p.m. "based on the CEC [California Energy Commission] hourly forecast for the 2020-2030 California Energy Demand Revised Forecast." Conspicuously missing in the San Diego – Imperial Valley Area peak time designation is the "based on" note. The lack of any factual basis or supporting data for the conclusions reached for the San Diego – Imperial Valley area raises the concern that CAISO failed to use the California Energy Commission ("CEC") 2020-2030 California Energy Demand Revised Forecast for the San Diego – Imperial Valley Area. Nor does CAISO provide any basis for shifting the peak demand away from the historically-recorded peak time of day. The final version of the LCR Report should detail the basis for each projected load forecast and it should use historically accurate data to develop its peak load conclusions for all LCRs The following figure compares the net demand curve for 2018 and 2019 to the CAISO's projected net demand curve for 2021. As noted in Figure 1, the hourly average peak demand in SDG&E service territory has never occurred later than the 5-6 p.m. hour during the last 5 years. Figure 2 shows that CAISO's projection shifts the peak demand hour a full two hours later than the latest historical peak demand. CAISO must provide a strong basis for such an unprecedented and dramatic shift in the peak demand window to justify its assertion that the peak energy use in the San Diego – Imperial Valley Area will occur at 8:00 PM. Time of day projections have a big impact on the peak demand. First, the later in the day the peak occurs, the lower the demand will be. CAISO projected the peak net load for 2021 at 4415 MW. While 4415 is 8.5% higher than 2019's peak load, CAISO's projection is 15% higher than 2019's 8:00 p.m. demand on the same day. The magnitude of the difference between CAISO's projected peak and the 2019 historical load equates to the entire Planning Reserve	Same comment as above.

No	Comment Submitted	CAISO Response
	Margin used to determine system RA need. CAISO's projected load is simply too high to be believable for an 8:00 p.m. peak. If the Final LCR Report has not corrected the overestimation of peak load, then SDG&E customers will pay for more peak load capacity than needed and they will also pay for more RA capacity than needed. CAISO must revise the Final LCR report to eliminate over-procurement and protect ratepayers from unnecessary costs. Second, if CAISO revises the peak from 8:00 p.m. to the historical peak between 5:00 p.m. and 6:00 p.m., then, all solar generators' contributions to serving peak load increase dramatically. The CAISO Draft LCR Report assumes the BTM contribution at 8:00 p.m. at 0 MW. However, even at the end of the 5:00 p.m. to 6:00 p.m. hour on September 1, 2019, solar was still producing at 39% of its peak capacity for the day. Figure 3 below details the change in contribution from solar resources depending on the time of day. SDG&E produces 20% of its energy from in front of the meter solar. An additional 1,260 MW of BTM solar contributes to a reduction in net load prior to sunset in SDG&E service territory. Thus, CAISO must either lower its peak demand projection for the 8:00 p.m. time due to dramatically lower historical use at that time of day, or the CAISO must lower its peak demand projection by revising the time of peak demand to earlier in the day when solar can - and does - serve peak load. **C. CAISO incorrectly assumes that peak demand will grow in the San Diego – Imperial Valley Area.** The CAISO Draft LRC Report assumes peak load growth each year between now and 2025. The Draft LCR Report lacks any factual basis for its assumption of load growth. The facts on the ground tell a different story than the one assumed by CAISO. A multitude of factors will continue to push down the peak demand in SDG&E service territory instead of the annual 38 MW/year increase that CAISO forecasts. The peak demand will see downward pressure from high electricity prices, high BTM solar installations, increases in time-of-use (TOU) roll-out, and quickly increasing storage deployment. Electricity prices in SDG&E territory are already the highest in the state. SDG&E's rates will increase by another 17.27% from 2019 to 2021 because of the costs allowed in SDG&E's most recent General Rate Case decision. High electricity prices incentivize customers' switching to alternative energy supplies, including BTM solar. BTM solar in SDG&E territory has already achieve the second highest per capita capacity as well as the second highest total capacity	As established above CAISO is using a CEC commission approved load forecast.

No	Comment Submitted	CAISO Response
	in the nation. Since 2015, BTM solar installations in SDG&E territory have averaged 188 MW per year, and the pace is accelerating. 2019 saw record BTM solar installations at 215 MW. As SDG&E electricity prices continue to increase, the payback time for a BTM system will continue to drop. The payback time in SDG&E service territory including a battery was less than 7 years as of 2018. Energy storage will eliminate many customers' total demand during the 4:00 p.m. to 9:00 p.m. window. Time-of-use rates will continue to push down demand as well especially in SDG&E territory with high solar adoption because solar customers cannot opt-out of TOU. TOU will encourage load shifting through behavioral change and by way of storage-based demand control. Battery installations showed rapid growth in 2019, and Bloomberg New Energy Finance projects that residential battery installations will increase by a factor of 5 in California in 2020 from approximately 10,000 units in 2019 to 50,000 units in 2020. As batteries drop in price, Wood Mackenzie Power and Renewables projects grid scale storage to increase thirteen fold over the next six years. New batteries in 2020-2024 could wipe out much of customer's electricity demand from 4-9 p.m. High electricity prices, low BTM solar prices, TOU, and battery storage will all contribute to a lower peak demand each year in SDG&E service territory. CAISO should revise its forecast to reflect these facts.	
6e	**Conclusion** For the reasons noted above, the CAISO should limit reliability standards to the NERC and WECC standards, streamline and simplify the LCR demand projections, and correct the San Diego – Imperial Valley Area demand projections. For the final version of the LCR report, the CAISO must correct its inaccurate and unsubstantiated San Diego – Imperial Valley Area demand projections. Otherwise, the Final LCR Report's findings will result in excessive energy and capacity procurement resulting in wasted ratepayer dollars.	CAISO disagrees with the conclusions reached by POC as indicated in the CAISO responses to the comments above.

7. Center for Community Energy (CCE)
Submitted by: Jose Torre-Bueno

No	Comment Submitted	CAISO Response
7a	**Meta Comments** Our main comment is actually a meta comment in that it addresses not the content of the document, which is excellent engineering work, but the underlying economic assumptions going into it which recent tragic events have drastically altered.	The comments about the engineering work are appreciated.
7b	**California Has Experienced a "Black Swan" Event** As it says in the report: "The inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2021 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on October 31, 2019". At that time no one could have anticipated the situation we now find ourselves in. Because of the COVID-19 lockdown as of today, CAISO energy consumption is down almost 8% relative to a year ago. There is no reason to expect usage to bounce back quickly; in fact, there is a very real risk that the health and economic crisis will trigger a depression of several years' duration. The IMF is predicting the worst recession since 1930s. For this reason, the demand forecast used in the report the "mid baseline demand with low additional achievable energy efficiency and photo voltaic (AAEE-AAPV)," which was developed in 2019, should now be considered completely obsolete. In particular, the CCE considerers the prediction in the demand forecast – that Peak Demand in the SDG&E TAC Area will grow by 38MW/year between 2021 and 2025 – to be no longer valid.	Your comment has been noted.
7c	**The Feasibility of Predicting Future Demand is Permanently Impaired** Over and above the impact of the COVID-19 lockdown on the economy, a number of social and technological changes have emerged which can add variables of unknown magnitude to models attempting to predict future demand peaks. • Even after the lockdown ends, companies and workers who have been forced to try telecommuting may decide some of the benefits of reduced commuting and office rental space savings are compelling enough that the number of	Your comment has been noted.

No	Comment Submitted	CAISO Response
	remote workers may not return to the previous low numbers. This can be expected to change the pattern of daily load. • The Public Safety Power Shutoff program has already led to a great increase in interest in behind the meter batteries. These can be expected to be used for load shifting as well as for emergency power. CCE suggests that the trauma of the COVID-19 crisis, which has led to hording of everything from toilet paper to ammunition, will in the long run also lead to a greater interest in behind the meter batteries as consumers become interested in “hording” electricity even if it does not make economic sense. This may be speculation, but speculation is all we have to go on at this point. • California state policy has begun to encourage building electrification. Going forward, we can anticipate that smart building systems, especially those combined with batteries, will be much better at leveling their demand curve. • New technologies, especially vehicle to grid energy transfer and advanced Demand Reduction systems, can be expected to much better match solar production to demand. All of the above factors make predicting the future demand for electricity more difficult. In particular, predicting the future peak demand multiple years into the future in the face of multiple rapid technological and social changes is going to become increasingly difficult.	
7d	**New Facilities to Meet RA Requirements Can Be Brought Online More Quickly** While prediction is becoming more difficult, it is perhaps fortunate that the lead time to bring facilities to meet peak demand online is being reduced. In particular, it is clear that battery projects can be brought online much faster than conventional generating projects, and the rate at which they can be implemented is improving. The Alamitos 100MW/400MWh project, which was contracted from AES in 2014, will finish in December 2020. In contrast, Clean Power Alliance contracted for a new 100MW/400MWh system from sPower (a subsidiary of AES) on April 10, 2020, and expects operation August 2021, only 16 months later. Negotiations for this system started only 6 months ago. The first large scale battery system to be brought online quickly was, of course, the Hornsdale Power Reserve system in Australia, which was famously built in less than 100 days	While battery/storage resources can become operational rather quick, there is a limited capacity that can seamlessly integrate in local areas as illustrated in the study results. The CAISO will continue to assess alternatives to reduce gas-fired generation and increase storage capability in the local capacity areas through the CAISO transmission planning process.

No	Comment Submitted	CAISO Response
	This means that LSE have a greater ability to rapidly adjust their Local RA (LRA) capacity than was true in the past.	
7e	**Conclusion** The purpose of the multi-year requirement for LSEs to contract LRA is to provide market signals. The assumption is that the facilities that are needed to provide the LRA are inherently slow to build, so the LSEs need to place contracts now for LRA in the future so that the market signals will cause these facilities to come into being. The CCE suggests that this assumption no longer holds and the need for long term future requirements for LRA should be re-examined. If facilities to meet LRA needs can be built quickly, but the ability to predict LRA multiple years into the future is weak, then requiring LSE to contract for LRA actually creates risk. Requiring LSEs to contract for LRA three years in the future will run the risk of burdening them and their ratepayers with significant excess capacity. Further, at this moment most RA that can be procured is from fossil fuel plants that are not in keeping with the state's GHG reduction goals. Given that the cost of energy storage is decreasing rapidly, and that storage can be deployed more rapidly than other types of LRA, procuring future LRA from traditional generators at this time is not necessarily a good long-term strategy for LSEs. There is a further consideration for CCAs. Unlike an IOU, a CCA is more like a municipally owned utility in that it is a creation of local government and arguably should have a greater autonomy to decide how much risk it chooses to accept relative to the cost of acquiring future LRA.	Your opinion has been noted.

8. Pacific Gas and Electric (PG&E) **Submitted by: Matt Lecar**		
No	**Comment Submitted**	**CAISO Response**
8a	**DISCUSSION** PG&E previously provided comments directly to the California Independent System Operator Corporation ("CAISO") on the Draft 2021 LCR Report, on March 31, 2020. The comments below mirror those previously provided to the CAISO.	The CAISO has provided written response to comments provided by PG&E.
8b	**PG&E Requests that CAISO Provide Additional Clarity for not Applying PG&E's Spare Equipment Strategy That Would Result in a Lower LCR MW Need While Also Meeting the Reliability Standards** Through the CAISO's process for establishing 2021 local capacity area requirements ("LCR") for the Greater Bay Area, the CAISO has identified that an outage of both Metcalf 500/230 kilovolt ("kV") #11 & #12 Transformer Banks (T-1-1) results in an overload of the remaining Metcalf 500/230 kV #13 Transformer Bank. This double three-phase transformer bank outage and resulting overload increased the LCR for the Greater Bay Area by roughly 1,800 megawatts ("MW"), which resulted in a total LCR for the Greater Bay Area of 6,353 MW, as calculated by the CAISO, as compared to last year's study results of 4,550 MW. This increase is primarily due to a change in LCR criteria, in which CAISO now considers a T-1-1 (i.e. loss of a transformer followed by the loss of second transformer) in its calculation of the LCR. This double three-phase transformer bank outage was not considered in the previous LCR criteria, and PG&E believes that this three-phase transformer bank outage criteria should not be applied at the Metcalf 500 kV substation given PG&E's layered and robust strategy for addressing the loss of high voltage transformers at the Metcalf substation as outlined in comments provided directly to the CAISO on the Draft 2021 LCR Report. On April 9, 2020, CAISO provided the following response to PG&E's spare equipment strategy: "The CAISO operators need to readjust the system within 30 minutes in order to prepare for the next most limiting contingency and while the PG&E plan is to replace a failed Metcalf transformer bank within 24 hours, its strategy is to rely on internal resources within the Bay Area in the interim. The CAISO must include those resources as required to meet the standards and therefore	The CAISO appreciates the layered and robust strategy for addressing the loss of high voltage transformers at the Metcalf substation. The CAISO cannot waive the CAISO Tariff requirement to comply with the NERC mandatory criteria, which is not met because PG&E cannot re-dispatch the system within 30 minutes and therefore it must rely on Bay Area internal generation for 12-24 hours while replacing the failed single phase bank out with the available spare.

No	Comment Submitted	CAISO Response
	included in the LCR requirement. The CAISO will continue to work with PG&E planning and operations departments to explore options that can be implemented such that within 30 minutes after the loss of the transformer bank, the flows from Metcalf are diverted to other 500/230 kV stations serving the Bay Area in a manner that will result in reduction of local capacity requirement. PG&E should move forward expeditiously with rerates for the Metcalf 500/230 kV transformer banks if technical data supports such an action.	
	PG&E requests that CAISO provide additional information in response to PG&E's spare equipment strategy. PG&E notes that the North American Electric Reliability Corporation's ("NERC") reliability standard contemplates that: "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed."	This NERC requirement states that the planning needs to be done with one transformer bank out of service as a normal condition before any other contingencies are taken such that its loss impact is fully addressed. The NERC requirement further strengthens CAISO view that the loss of two banks needs to be studied and addressed.
	Further, the Federal Energy Regulatory Commission ("FERC") in Order 693 also considered this same issue and discussed the relationship between transformer outages and a spare equipment strategy: "…the consideration of planned outages is inextricably linked with spare equipment strategy. Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under the most stressed system conditions likely to be experienced."	The referenced section of Order 693 refers to planned outage and was prior to the approval of the current FERC approved NERC TPL standard. In the Metcalf case a planned outage shall not be considered during peak system conditions. The LCR studies deal with forced outages not planned and they can happen at any time including peak conditions.
	In the case of PG&E's spare equipment strategy at the Metcalf substation, both failed transformer banks would be back in-service well within the one-year period specified in the NERC standard and as contemplated in FERC Order 693. It is also important to provide more information about the robust design of the 500/230 kV transformer banks. A single transformer bank is made up of three single-phase units. At locations such as Metcalf that have three transformer banks, there are two single-phase spare units to support the other nine units that make up the three transformer banks in the station. This means there are eleven phases total that are isolated from one another. If the first transformer	The spare equipment strategy is not relevant to forced outage studies and TPL-001-4 requirement for T-1, system adjustment followed by the next T-1. The conditions of TPL-001-4 sets out more stringent requirements if the spare strategy would result in equipment being out of service for more than one year.

No	Comment Submitted	CAISO Response
	bank (i.e. all three single-phase units) are out for planned maintenance, the next unplanned transformer outage would not be the loss of another transformer bank, but the loss of a single-phase unit that could be replaced by the available spares onsite. Given PG&E's robust and layered 500/230 kV transformer bank spare equipment strategy, in which a failure of a transformer bank could be mitigated in mere hours or the loss of a second transformer bank could be mitigated in a matter of weeks while keeping two 500/230 kV transformer banks energized, PG&E requests that CAISO provide additional clarity for not applying PG&E's spare equipment strategy that would result in a lower LCR MW need while also meeting the reliability standards.	CAISO only looks at forced outages across the peak and the timelines required for readjustment, 30 minutes or the time dictated by the duration of the equipment's emergency rating as specified in the CAISO Transmission Register (TR). Planned outages are out of the scope of this study.
8c	**CONCLUSION** PG&E appreciates the opportunity to provide these opening comments to the Draft 2021 LCR Report.	Thank you for your comments.