The ISO received comments on the topics discussed at the October 31, 2017 stakeholder call from the following:

1. California Public Utilities Commission (CPUC)
2. Pacific Gas & Electric (PG&E)
3. San Diego Gas & Electric (SDG&E)
4. Center for Energy Efficiency and Renewable Technologies (CEERT)
5. Sierra Club, Earthjustice

Copies of the comments submitted are located on the Local Capacity Requirements Process Page at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

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

No	Comment Submitted	CAISO Response
1	**California Public Utilities Commission** **Submitted by: Michele Kito and Jaime Rose Gannon**	
1a	**Energy Division Appreciates CAISO's Efforts to Revise Its Local Capacity Technical Study Schedule** In its October 31, 2017, presentation, CAISO presented an alternative schedule "to potentially reduce the schedule to finalize the year 1 LCR reports from May 1 to April 16, 2018 per CPUC request." CAISO indicated that the critical path item is an adopted IEPR forecast by January 19, 2018, a reduction in time for stakeholder comments and deferring the year 5 LCR studies after the year 1 LCR study results. Energy Division staff supports these efforts and notes that it does not believe that delaying the 5 year studies modestly will have any adverse consequences. Accordingly, Energy Division staff agrees that the timeline should be revised and an alternative schedule should be released in order to provide parties sufficient time to plan.	Pending industry support for this change, the ISO will revise the timeline with the new schedule as proposed. The ISO notes that the ISO intends to use the 2019 LCR study as a test year to see if the new process timelines can be met, as such adjustments may be necessary as studies progress.
1b	**CAISO Should Provide Local Area and Sub-Area Load Data** In the interest of transparency, Energy Division staff recommends that CAISO provide the 1-in-10 load forecasts and historical data for each local area and sub-area. While CAISO provides the 1-in-10 forecast for the local area in aggregate, CAISO does not provide the sub-area load forecast in its final technical report in all instances. In addition, Energy Division staff recommends that CAISO provide historical load information for each local area and sub-area, similar to the historical load data for the Moorpark Subarea that was made available to parties on September 28, 2017, in response to a date request from CEERT.	The ISO has not established electrical boundary definitions applicable to load for each sub-area and in many cases it is not practical to do so. Many sub-area needs are not serving a discrete and definable radial load pocket and therefore load boundaries cannot be readily defined. Therefore we cannot reasonably provide load forecast data or historical data for all sub-areas. Currently resources are catalogued as being needed for sub-area requirements because they are effective in mitigating the particular sub-area constraint in any particular year (resource effectiveness data is directly extracted from current software capabilities). The ISO did make a special effort to define and pool historical and forecasted load data for the Moorpark sub-area to address the specific issues being examined in the regulatory proceedings ongoing at the time. However, the ISO does not believe this level of effort nor the significant increase to the study time that would be required is warranted for all approximatively 46 sub-areas. Planning efforts to reduce reliance on local capacity resources will continue within the transmission planning process targeting major areas of interest and outside of the LCR study process.

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<tr><th>No</th><th>Comment Submitted</th><th>CAISO Response</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>1c</td><td>CAISO Should Use a Coincidence Adjustment for its Combined LA Basin/San Diego Area

As we indicated in comments last year and on the stakeholder call, Energy Division staff continues to recommend that CAISO use a coincident peak for the combined LA Basin and San Diego sub-area analysis. It is our understanding that CAISO currently combines the 1-in-10 non-coincident peak for LA Basin and adds this to the 1-in-10 non-coincident peak for the San Diego sub-area, which we believe could materially overstate the combined 1-in-10 peak for the areas. San Diego typically peaks at a different time than LA Basin and this should be taken into consideration in the CAISO analysis for the combined areas.</td><td>Based on the ISO's review of peak load data, the LA Basin and San Diego areas tend to peak at approximately the same time. The following are a few examples where peak loads are either peaking at the same (with one or days apart) or same day with less than half hour difference.
<table><tr><th>PTO</th><th>Peak Load (MW)</th><th>Time</th></tr><tr><td>SDG&E</td><td>4551.0</td><td>9/1/2017 15:53:00</td></tr><tr><td>SCE</td><td>24380.2</td><td>9/1/2017 15:42:00</td></tr><tr><td>SDG&E</td><td>4720.8</td><td>9/9/15 16:00</td></tr><tr><td>SCE</td><td>22863.0</td><td>9/8/15 16:00</td></tr><tr><td>SDG&E</td><td>4683.7</td><td>9/27/10 15:25:21</td></tr><tr><td>SCE</td><td>24061.2</td><td>9/27/10 14:52:03</td></tr><tr><td>SCE</td><td>23365.9</td><td>7/24/06 16:17:00</td></tr><tr><td>SDG&E</td><td>4591.4</td><td>7/22/06 16:23:00</td></tr></table>
During 2019 LCR studies the ISO intends to use the CEC load forecast provided in 8760 hours format. The ISO intends to work with the CEC and CPUC such that the load forecast data provided should already include any coincidence adjustment if warranted by available historical data.</td></tr>
<tr><td>1d</td><td>CAISO Should Work with the CPUC, CEC and the IOUs to Ensure Load Forecasts are Adjusted for Behind-the-Meter Local Capacity Procurement

As we indicated in our comments last year, Energy Division staff again recommends that CAISO work with the CPUC, CEC and the IOUs to ensure that the 1-in-10 load forecast is adjusted to take into consideration incremental behind-the-meter demand side resources that have been procured to meet local capacity requirements for 2019 through 2022. The CPUC authorized SCE and SDG&E to procure supply and demand-side resources to meet its local capacity requirements. If the load forecast is not adjusted to take the behind-the-meter incremental demand-side resources into account (e.g., energy efficiency), we</td><td>The ISO agrees that these programs need to be taken into account, and that care is needed to ensure that they are not inadvertently double counted nor modeled in the study case before its actual implementation date. By definition, "resources" that count towards meeting resource adequacy requirements, including local requirements, need to be metered and available to the ISO for dispatch under a "must-offer-obligation". A behind-the-meter reduction is a "load modifier", and not a resource. The ISO expects that the CEC load forecast (and its respective PTO allocation to each bus) accounts for all future load modifying programs including "incremental behind-the-meter demand</td></tr>
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No	Comment Submitted	CAISO Response
	believe that the local capacity requirements will be overstated and the demand-side resources will not reduce the LCR need as anticipated. Accordingly, CAISO should work the CPUC, CEC and IOUs to ensure that this issue is addressed appropriately.	side". Furthermore, once an individual program is "in-service" and its behavior captured in actual real-time data used by the CEC for its future forecasting, the CEC needs to stop accounting for it through a further downward adjustment in order to avoid double-counting.
1e	**CAISO Should Conduct Separate Analyses for LA Basin and San Diego in Addition to the Combined Analysis** As indicated on the stakeholder call, Energy Division staff requests that CAISO conduct an analysis for San Diego separate from LA Basin. While in 2012 LTPP analyses it was assumed that resources were somewhat fungible between San Diego and LA Basin (and, thus, the Commission considered different allocations of requirements in those areas), more recently, CAISO has indicated that resources in the Western LA Basin are only "minimally" effective at meeting needs in San Diego, thus calling into question why these areas continue to be combined for study purposes (especially the "overall combined LA Basin-San Diego-Imperial Valley area LCR, as conducted for 2018). At the very least, Energy Division staff would like to understand how procuring resources in one region affect the requirements in the other and requests further clarify on this issue.	The increased interrelationship between the LA Basin area and the San Diego Imperial Valley area was appropriately recognized in the 2012 LTPP Track 4 Commission decision given the effect of the early retirement of SONGS removing the buffering effect that facility had on the interactions between the two areas. While the resources in each area are not directly substitutable for resources in the other, e.g. less effective and the effectiveness is generally not linear depending on the system conditions being examined, the effects do need to be taken into account in landing on the overall lowest local capacity requirement. To be helpful, the ISO could work with the CPUC to develop and study two sensitivities by varying slightly up and down resources in one area to assess the impact on resource requirements in the other. We will discuss with the CPUC staff how and where to document these sensitivity results.
1f	**CAISO Should Consider Seasonal Local Requirements** As discussed previously, Energy Division staff request that CAISO again consider seasonal local requirements. This issue is particularly important in the San Diego region, where the local requirements now exceed 4,100 MW (see below), even though the 1-in-2 load forecast is below 4,000 MW in all months, except September.	An ISO waiver already exists for this requirement, such that any LSE only need make a showing each month with local resources up to their monthly RA system need when the monthly RA system need is below their yearly local RA allocation. SDG&E TAC area LSEs do have the highest load ratio of local requirements vs their system requirements. Options to reduce the local capacity requirements will continue to be explored via the transmission planning process. As for San Diego-Imperial Valley seasonal local requirements the ISO has performed a non-summer season study (see page 106-108 http://www.caiso.com/Documents/April302012LCTStudyReport2013indocketnoR1110023.pdf). The other season LCR requirements were 200-

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<tr><th></th><th>San Diego/IV</th><th>San Diego Sub-Area</th><th>LA Basin</th><th>Contingency</th></tr>
<tr><td>2016</td><td>2,850</td><td>3,112[1]</td><td>8,887</td><td>SD/IV –loss of 500 kV SWPL btw. IV and N. Gila and Otay Mesa outage
SD Sub-Area- loss of Octillo-Suncrest 500 kV followed by ECO-Miguel 500 kV
LA – Lugo-Victorville 500 kV followed by Sylmar-Gould 230 kV.</td></tr>
<tr><td>2017 (SD Sub-Area and LA combined)</td><td></td><td>2,743</td><td>7,094</td><td>SD Sub-Area and LA Combined – loss of ECO-Miguel 500 kV followed by Octillo-Suncrest 500 kV</td></tr>
<tr><td>2017 (SD Sub-Area and LA Basin combined)</td><td>3,570 (later changed to 4,635 in 2018 study)</td><td>2,915</td><td>7,368</td><td>SD/IV – SWPL btw. IV and N. Gila and TDM outage
SD Sub-Area and LA Combined – loss of Lugo-Victorville 500 kV followed by Sylamar-Gould 230 kV</td></tr>
<tr><td>2018 (LA Basin-SD Sub-Area and IV combined)</td><td>4,032 (but > 4,100 with collective deficiency)</td><td>2,157</td><td>7,525</td><td>SD Sub-Area - ECO-Miguel 500 kV followed by outage of Ocotillo-Suncrest 500 kV
LA Basin-SD Sub-Area and IV Combined – same as LA Basin
LA Basin – loss of Lugo-Victorville 500 kV followed by Sylamar-Gould 230 kV</td></tr>
</table>
</td><td>300 MW lower for the San Diego sub-area and 200-300 higher for the San Diego-Imperial Valley area, after accounting for required transmission and resource maintenance. Therefore it demonstrated that the seasonal approach does not necessarily eliminate or even help reduce the current LCR need levels.

The ISO also considers that there are a number of technical, market and RA program design issues that need to be addressed holistically, rather than in a piecemeal fashion.

In the meantime, the current local RA construct is easier for stakeholders to manage and implement, provides the ISO with resources needed to maintain local reliability standards year round and seeks a low cost solution for all parties (ISO, CPUC, LRAs, LSEs and resources owners).</td></tr>
<tr><td>1g</td><td>Energy Division Staff Continues to be Concerned About CAISO's Peak Shift Analyses

In its draft study manual, CAISO indicates the following about its base case and peak-shift analysis:

The ISO will use the CEC energy and demand forecast for the base scenario analysis. If not directly included in the CEC forecast, the ISO will conduct additional scenarios on a case by case basis regarding the peak shift issue discussed above consistent with the ISO transmission planning process and compliance comply with the NERC TPL-001-4 mandatory reliability standard. These additional scenarios will be considered on a case by case basis to avoid lowering existing or historical reliability levels when assessing the local areas, and in particular areas at risk of generation retirement, until such time as the peak shift issue discussed above has been addressed in future CEC load forecasts. At this time, only southern California's combined LA Basin and San Diego areas have been identified as necessitating this additional scenario analysis, based on 2018 analysis. The ISO will continue to work with the CEC on the hourly load forecast issue during the development of the 2017 IEPR and the 2018 IEPR Update.</td><td>The ISO's intention is to use the new CEC forecast in 8760 hours format, and in particular, relying on the CEC's load modifier information, to the greatest extent possible. (Note that the CEC 2017 IEPR forecast will only provide hourly load and load modifier information at a TAC-area level of granularity.)</td></tr>
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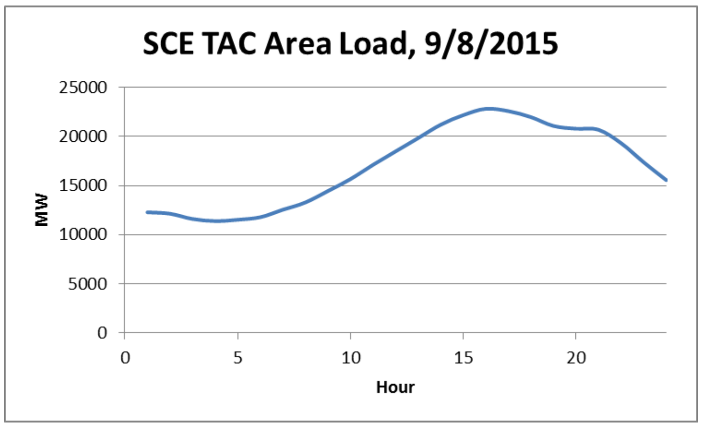
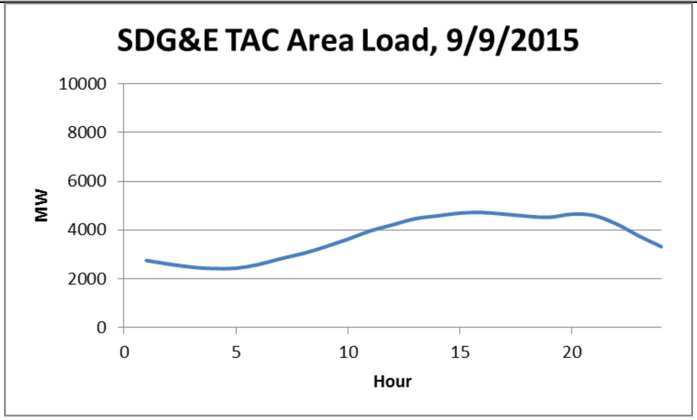
No	Comment Submitted	CAISO Response
	Energy Division staff remains concerned about how the CAISO will implement this peak shift analysis based on the methodology it used in the 2017 studies. For the 2018 studies, CAISO used the CEC's peak-shift analysis, but provides no detail on how it will conduct a peak shift analysis for 2019, if necessary. Energy Division staff believes that CAISO's previous methodology, of additing back in all of the behind-the-meter generation to the CEC's base case forecast would be flawed and would overstate the loads in these areas. CAISO's methodology is flawed because it does not take into consideration the fact that consumption loads decline by 6 p, so adding behind-the-meter generation that occurs during the 4 pm peak to the 6 pm hour will result in a higher load than will be seen at the 6 pm hour. This is illustrated in the figures below. 	

No	Comment Submitted	CAISO Response
	 As illustrated, for the SCE TAC area, if PV is added back in at 4 pm, this will vastly overstate the sales load at both the 4 pm and certainly the 6 pm hour. Moreover, the CAISO's peak shift adjustment is likely even more problematic for the combined area, for which the peak is likely to be driven by the SCE area. In sum, given the shape of these sales load curves, we believe that CAISO's peak shift adjustment used for 2017 is likely to be flawed and this methodology should not be used in the 2019 study. In addition, the final draft study manual should be revised to indicate that the time of peak demand could be 6 pm – that is, page 9 should be revised to state that "the ISO will continue to perform additional assessment of the reliability impacts when loads continue to remain high as forecasted by the CEC but without the contribution of solar voltaic distributed generation at an early evening hour (e.g., 6:00 p.m.)" rather than (i.e., 6 p.m.).	

No	Comment Submitted	CAISO Response
2	**Pacific Gas & Electric (PG&E)** **Submitted by: Matt Lecar**	
2a	**PG&E requests the CAISO provide as much transparency as possible into the analysis so that a reasonably well-informed and technically capable party may be able to replicate the results of the study.** In particular, PG&E requests more information be provided about the system adjustments the CAISO makes as part of the study. Of particular interest, is when the study examines an N-1-1 situation in local areas, and as such adjustments are made to the system as following the first contingency to restore the system to a secure state before a second contingency occurs. The CAISO identifies explicitly the first and second contingencies, but does not provide information about the adjustments made to the system between them. PG&E would like the CAISO to provide more information regarding these system adjustments. PG&E understands the imprudence of the CAISO describing exactly the adjustments made, but believes the CAISO could provide a general description of the adjustment in each particular sub-area. Such a description would provide greater insight into the requirements set in the process, and allow for the analysis to be replicated. Such information would also allow for a greater link to be established between the LCR process and the transmission planning process (TPP) where transmission reliability needs are identified and addressed through specific modifications to the transmission system.	ISO believes the LCR Manual http://www.caiso.com/Documents/2019LocalCapacityRequirementsDraftStudyManual.pdf is as specific as it can be, without giving out exact resource dispatch, in regards to system adjustments between N-1 and the next N-1. "a) System configuration change – based on validated and approved operating procedures b) Decrease generation from units that aggravate the constraint (deliverability is not protected for this P6 category). Stop decreasing a certain generator when: i. Another known flow limit in the system has been reached. ii. Total generation decrease reaches 1150 MW – limit given by single contingency SPS as part of the ISO Grid Planning standards (ISO SPS3)." Of course one would want to decrease first the resources that are the most effective in aggravating the constraint (if possible per i and ii). System adjustment is not always possible or effective in reducing the need, especially for areas and sub-area that are mostly radial in nature. ISO does not make public exact resource dispatch (used during system re-dispatch or any other way) therefore the ISO cannot give a more specific language by sub-area than that already included in the Manual.
2b	**PG&E also requests the CAISO be more explicit about its assumptions regarding generation unit ownership in the analysis.** For example, during the call, CAISO staff described the process for identifying which generation resources are considered first for mitigating contingencies in local areas and subareas. The CAISO studies the "most effective" resource first, but will also consider long-term contracted units such as PURPA Qualifying Facilities (QFs) and Utility Owned Generation (UOG), even if they are less effective, because these units are assumed to be available. If this is, in fact, how	The methodology is clearly described in the LCR Manual: "Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating: a. QF/Nuclear/State/Federal units b. Units under known existing long-term contracts with LSEs c. Other market units without long-term contracts

No	Comment Submitted	CAISO Response
	ownership/contract information is incorporated in the analysis, PG&E asks these assumptions be made explicit in the methodology.	To determine a specific unit's categorization see Attachment A to the LCR report column titled "CAISO Tag". Resources listed as "Market" resources are usually considered in the last two categories. IOU owned resources and those provided by Local Regulatory Agency as being under long-term contract are categorized as subsection b. resources (units under known existing long-term contracts with LSEs). Remaining "Market" categorized resources are considered subsection c. resources (other market units without long-term contracts.)
2c	**Resource retirements** Further, PG&E asks the CAISO to be explicit about how assumptions regarding the electrical system, particularly generation assumptions, from the TPP flow through to the LCR analysis. While transmission system investments/retirements clearly flow from the TPP to the LCR, it is less clear how assumptions regarding generation on the system are handled. While, in the short-run, existing generators are likely to continue to exist, and 'known or announced retirements' or units over 40 years of age are not likely to exist, the CAISO is aware that units may change availability status quickly. Both the TPP and LCR analyses should be able to identify impacts on transmission system reliability and address detrimental impacts on a timely basis when specific resources become unavailable.	The scope of the LCR studies is to come up with the minimum LCR need among available resources. If a need is found the resource is required to meet reliability standards therefore it will not be allowed to retire. It is not the intent of the LCR study to come up with solutions to eliminate this need (either new transmission or a different resource mix solution). During the TPP process, new transmission projects or a different set of resource solutions can be considered as economic driven projects to eliminate or reduce reliance on existing resources. The results of the economic analysis usually depend on the yearly differential in price between these particular local resources and system RA resources vs. one year carrying change (or deferral value) of the transmission project or the differential in cost of existing resources vs new resources if replacement is preferred.
2d	**Holistic review of the RMR, TPP and LCR processes** PG&E understands that the CAISO intends to conduct a holistic review of the RMR process in the coming months. PG&E supports that effort and recommends that the TPP and LCR study processes be included in that review, with the aim of establishing consistent, transparent assumptions about the future availability of resources that support reliability in constrained local areas.	The comment has been noted.

No	Comment Submitted	CAISO Response
3	**San Diego Gas & Electric (SDG&E)** **Submitted by: Effat Moussa**	
3a	**The 2019 Local Capacity Area Technical Studies Should Provide Information to Local Regulatory Authorities (LRAs) to Assist in Determining whether LCR Costs are Being Fairly Apportioned.**	
	The CAISO's May 1, 2017 2018 Local Capacity Technical Analysis, Final Study Report and Study Results confirms that LA Basin area and the San Diego-Imperial Valley area "are electrically interdependent on each other." (page 55) This final study report describes the "iterative" process by which the "LCR needs for the respective areas are coordinated within the overall LA Basin-San Diego-Imperial Valley area." SDG&E understands that this iterative process minimizes the combined LCR for the LA Basin area and the San Diego-Imperial Valley area.	The same iterative process is envisioned to be used during the 2019 LCR studies as well.
	The October, 2017 version of the Draft Manual, 2019 Local Capacity Area Technical Study does not describe the iterative process that SDG&E expects will also be used to produce the year 2019 results. Such a description would be a useful addition to the manual.	ISO has included the appropriate language in page 15 of the 2019 LCR Manual.
	In any event, SDG&E supports the objective of minimizing the combined LCR. However, as in past years, SDG&E remains concerned that Load Serving Entities (LSEs) with obligations to secure dependable capacity to meet the respective LA Basin area and San Diego-Imperial Valley area LCRs, may be bearing too much or too little of the associated cost burden. As the final study report notes, the LCR in one area is "dependent on the amount of resources that are dispatched for the adjacent area and vice versa." Accordingly, it is possible that LSEs in one LCR area are incurring LCR costs that, in fact, materially benefit the LSEs in the other LCR area. Collectively, all LSEs may be better off, but that does not answer the question of whether LSEs in one LCR area, or the other, are bearing a fair share of the overall LCR costs.	
	To answer this question SDG&E recommends that the October, 2017 version of the manual be augmented with study results showing what the LA Basin area and San Diego-Imperial Valley area LCRs would be assuming the study	Please see response to question 1e above.

No	Comment Submitted	CAISO Response
	objective was to minimize the amount of LCR for each area without considering the amount of resources that are dispatched in the other area. These results would provide the CPUC and other stakeholders with an indication of the extent to which dependable generation in one LCR area is supporting a lower LCR in the other area. It might also provide a basis for LRAs to allocate the combined areas' LCR costs among the respective LSEs such that all LSEs bear a fair proportion of the costs. In the CPUC's Resource Adequacy Order Instituting Rulemaking (OIR), SDG&E submitted comments to the above effect. On 11/9/2017 the CAISO provided reply comments stating: "the 2018 CAISO local capacity report…identifies the requirements for San Diego-Imperial Valley area…and the corresponding Los Angeles Basin LCR need….It is unclear exactly what further studies SDG&E is requesting at this time and what information any such additional studies would provide, If SDG&E continues to believe that additional studies are warranted, it should raise that concern in the CAISO's LCR study process." To illustrate the "further studies" SDG&E has in mind, and to show how the information from these further studies could be used, consider the following strictly hypothetical example. Assume that the CAISO's results for 2019 indicate that to minimize the combined LCR for the LA Basin area and the San Diego-Imperial Valley area, the LA Basin LCR would be 7000 MW and the San Diego-Imperial Valley LCR would be 4000 MW. Assuming an LCR cost of $50/kW-year, LA Basin LSEs would incur $350 million in costs and San Diego-Imperial Valley LSEs would incur $200 million in costs. Combined LCR costs would be $550 million.	
	Assume that an LCR study minimizing the amount of LCR for each area without considering the amount of resources that are dispatched in the other area, produces an LA Basin LCR of 8000 MW and a San Diego-Imperial Valley LCR of 3500 MW. These results suggest that dispatching an additional 500 MW of resources in the San Diego-Imperial Valley area (4000 – 3500) allows for 1000 MW less to be dispatched in the LA Basin LCR area (7000 – 8000). If these results are used to allocate the $550 million in combined LCR costs, then LA Basin LSEs would be responsible for $383 million in LCR costs {550 x	Please see response to question 1e above.

No	Comment Submitted	CAISO Response
	[8000/(8000+3500)]} and San Diego-Imperial Valley LSEs would be responsible for $167 million in LCR costs {550 x [3500/(8000+3500)]}.	
3b	**The LCR for the Combined LA Basin and Greater Imperial Valley-San Diego Areas Should be Based on Studies Using Coincident Peak Loads.** The October, 2017 version of the manual indicates that the CAISO intends to "…perform additional assessments of the reliability impacts when loads continue to remain high as forecasted by the CEC but without the contribution of solar photovoltaic distributed generation at an early evening hour (i.e., 6:00 p.m.)." (page 9) SDG&E understands that because the Greater Imperial Valley-San Diego area has a higher proportion of rooftop solar PV than LA Basin area, the CEC expects the peak load for the Greater Imperial Valley-San Diego area to occur at a later hour than for the LA Basin area. For purposes of establishing the combined LA Basin and Greater Imperial Valley-San Diego LCR, the studies should use load levels whose timing is coincident between the two areas. The October, 2017 version of the manual should be augmented to make it clear that studies establishing the combined LA Basin and Greater Imperial Valley-San Diego LCR should use data which is coincident in time between the two LCR areas. Further, a coincident time should be used for both the LA Basin and Imperial Valley-San Diego areas when determining the separate LA Basin LCR. Likewise, a coincident time should be used for both the LA Basin and Imperial Valley-San Diego areas when determining the separate Imperial Valley-San Diego LCR. It is possible, therefore, that three different coincident time periods may need to be evaluated.	Please see responses to questions 1c and 1g above. For electrically independent sub-area problems, a different peak load non-coincident with the main area peak load time period may need to be evaluated depending on the eventual materiality demonstrated in the load data.
3c	**Establish a Criteria for Determining the Circumstances Under Which Normal Ratings, Short-Term Emergency Ratings and Long-Term Emergency Ratings will be Used in LCR Studies.** The October, 2017 version of the manual includes a discussion of "Applicable Ratings." The discussion states:	The criteria for use of normal, long-term and short-term emergency rating exists and is included in the manual.

No	Comment Submitted	CAISO Response
	"short-term emergency ratings, if available, can be used as long as 'system readjustment' is provided in the 'short-time' available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings." (page 13) For the 2018 LCR studies, the CAISO used "normal ratings" for IID's "S-Line" when determining the maximum level of imports into the San Diego area under contingency conditions. The CAISO indicated that the 30-minute emergency rating for the S-Line was not applicable because the contingency condition could last for longer than 30 minutes and the CAISO had no assurance that "system readjustment" could be made within 30 minutes to reduce "S-Line" flows from the short-term emergency rating down to the normal rating. The CAISO has many tools, including generator curtailment provisions -- via Exceptional Dispatch orders in Participating Generator Agreements (PGAs) -- that should be utilized to readjust the system within 30 minutes. SDG&E notes that the system conditions assumed for purposes of setting LCRs are extreme: a 1 in 10 load condition overlapping with one critical outage, and preparation for a second overlapping critical outage. Given this extreme system condition, the CAISO should rely on all system readjustment tools at its disposal. The October, 2017 version of the manual needs to be augmented to explain the basis for deciding the duration of contingency conditions, and specifically what assurances the CAISO requires for accepting that "system readjustment" within the emergency rating period will occur.	The ISO does rely on system readjustment tools available in the operating time frame. Following the first contingency, the ISO would commit and dispatch generation to relieve the constraint. In addition the Imperial Valley phase shifters would be adjusted and various reactive support devices would be adjusted as needed, all to prepare for the next contingency. All of these adjustments are assumed to be completed prior to the second contingency in the ISO planning studies. However, it is possible that some of these adjustments could be performed after the second contingency and operations could rely on the 30 minute emergency rating for the S-Line to allow time for some of the adjustments described above to be performed after the second contingency.
3d	**Has the Impact of Public Appeals Been Fully Accounted For?** SDG&E requests that the CAISO opine on whether public appeals during a one-in-ten heat event are fully accounted for in the LCR studies. For example, would the expected response to public appeals provide the assurance necessary for the CAISO to rely on 30 minute emergency ratings following a contingency?	To the extent public appeals have occurred in the past and may have impacted historical load data, the impact of public appeals have been taken into account in developing forecasts based off of that historical data. Beyond that, it would not be appropriate to rely on additional adjustments in anticipation of future public appeals, as those reductions still reflect reductions in firm load.

No	Comment Submitted	CAISO Response
3e	**It is Reasonable to Assume Flow Control Devices will be Set to Minimize LCRs.** The October, 2017 version of the manual does not specifically address phase shifter settings. It does, however, state that "import capability into the local area shall be maximized, thus minimizing the generation required in the local area to meet reliability requirements." (page 7) Consistent with this study methodology, SDG&E suggests the October, 2017 version of the manual be augmented to make it clear that phase shifters under the operational control of the CAISO will have angles set (within the range of the device) so as to maximize flows into the LCR area for the most severe contingency condition.	The ISO intends to use all available transmission equipment (including flow control devices) in a manner that minimizes the LCR needs up to either the rating of the equipment itself or until another transmission element becomes binding (like 230 kV CFE transmission lines in the La Rosita-Tijuana corridor). We consider that the narrative already in the manual adequately reflects this broadly, and it is not practical to call out individually each piece of equipment that would be operated according to the higher level principle.
3f	**Loads and Generation Dispatch in Adjacent Balancing Authorities should be Consistent with the Contingency Condition Being Studied.** Load levels and generation dispatch patterns in neighboring balancing authorities can have an effect on LCRs. For example, the relative dispatch of generation between the western and eastern sides of the northern Baja electrical system, can impact LCRs within the San Diego area. It is therefore important that these loads and generation dispatch patterns are consistent with the system condition that establishes the LCRs. This is potentially more critical as the times of the highest load hours changes as a result of differing penetrations of rooftop solar PV in different areas of the southwest. SDG&E continues to question whether the use of historically-based Maximum Import Capability (MIC) is appropriate considering that the LCR determination is forward-looking and assumes very extreme system conditions (e.g., a one-in-ten peak load level within the LCR area), while the historically-based MIC results from system conditions which may be quite different. SDG&E understands that a historically-based MIC is, by definition, "feasible;" however, forward-looking imports into the CAISO balancing authority using power-flow modeling would likewise be "feasible." Other than references to the historically-based MIC assumption, the October, 2017 version of the manual has no discussion of how load levels and generation dispatch patterns in adjacent balancing authorities should be set for study	Load pattern levels for neighboring control areas are in the base case as represented by those neighboring control areas into the WECC underlying base case. Adjustments can be made with the consent of the neighboring control area. The level of MIC that has been established is directly relevant to the LCR studies, and not the method used to establish the MIC. This level needs to be protected for all contingencies used during deliverability studies (P0, P1 and P7) since LSEs have the right to use these imports for system RA in the upcoming year and therefore they must continue to be deliverable. The ISO has control of resources within its balancing area, but does not have control of resources in adjacent balancing areas. In the LCR studies, a dispatch pattern in adjacent balancing areas is assumed that

No	Comment Submitted	CAISO Response
	purposes. It would be helpful to describe these settings, both pre-contingency and for purposes of system readjustment after an initial contingency. For example if a critical generator within the CAISO balancing authority is lost during an extreme heat event, system adjustments may be needed to bring imports from adjacent balancing authorities down to a level that will not violate thermal line ratings in the event there was a subsequent loss of a major transmission line within the CAISO balancing authority. SDG&E also recommends that a discussion of forward-looking imports into the CAISO balancing authority using power-flow modeling be added to the October, 2017 version of the manual. The October, 2017 version of the manual states that: "…import capability, relied upon in the RA program, deliverability status shall be maintained for all common mode contingencies (including all single contingencies as well as double circuit tower line and same right-of-way contingencies)…. After a single contingency during the "System Readjustment" all generating units as well as imports can be reduced (up to a limit – see system readjustment) in order to protect for the next most limiting contingency." (page 8)	generically reflects the MIC import level. Assuming particular adjustments to this generic dispatch pattern and dispatch level for resources in adjacent balancing areas after a first contingency to help mitigate the reliability issue and reduce local capacity requirement needs assumes a level of precise control of external generation resources that is not practical. The ISO notes that assistance can be sought from neighboring balancing authority areas to reduce imports on an emergency basis, but dictating the specific generation to be adjusted to achieve that reduced import is likely unreasonable. The ISO therefore does not support relying on such assumptions for the purpose of reducing the procurement of existing local generation. It should be noted that the actual dispatch pattern and dispatch level during an actual contingency event could represent more adverse conditions than are generically assumed in the LCR studies.
	SDG&E finds this language confusing. On the one hand, this language seems to indicate that LCR modeling should assume power flows from neighboring control areas are at the historically-based MIC level and that these imports are to be "maintained" for single contingencies. At least for the San Diego-Imperial Valley LCR area, maintaining imports at the historically-based MIC level are impossible following the first critical outage; doing so would result in thermal overloads should a second critical contingency occur. In general, historical imports during peak load hours are not limited because the first critical outage has not occurred. On the other hand, the language suggests "imports can be reduced" for the next most limiting contingency. This seems to be in conflict with the statement that	MIC may not be decreased for any P0, P1 and P7 contingencies – required to maintain the MIC itself deliverable. With the exception for areas on the grid where there are current operating procedures and agreements for such curtailment among the neighboring control areas. As for P3 and P6 events, the ISO may not decrease neighboring control area exports during "system readjustment" since the system is still in a single contingency condition (P1). However the ISO may adjust resources coming from the neighboring control area that participate in the ISO market. This adjustment must only be taken if the remaining resources in the neighboring control area cannot be at or exceed the current level of MIC.

No	Comment Submitted	CAISO Response
	imports are to be "maintained." SDG&E believes the above language in the October, 2017 version of the manual needs to be modified to clearly explain the treatment of imports from neighboring balancing authorities both before, and after, critical contingencies.	
3g	**Criteria for Dispatching Generators with Similar Technology.** The October, 2017 version of the manual describes the process for mitigating a reliability criteria violation as follows: "Go back to the units within the area that help reduce the flow on the most limiting element. Turn on these units (most effective unit first within each category – after you finish one category move to the most effective unit in the next category and so on) in the following order until the equipment is at the 100% of emergency rating: a. QF/Nuclear/State/Federal units b. Units under known existing long-term contracts with LSEs c. Other market units without long-term contracts" The manual does not describe the logic for this ordering. SDG&E wonders why it makes sense to dispatch units with existing long-term contracts ahead of other market units, especially if the other market units had lower operating costs. SDG&E also believes that, in practice, the CAISO makes exceptions to this ordering. For example, even though there are multiple units with similar technology at one location, not all of the units may be dispatched. This is problematic if generation at the particular location is effective in mitigating a reliability criteria violation. The October, 2017 version of the manual should be expanded to explain the logic for the CAISO's dispatch ordering. As well, the CAISO should detail any exceptions to this ordering.	The order of dispatch does not try to mimic real-time energy dispatch. The order of dispatch is driven by the need to be as accurate as one can in regards to RA capacity showings and the need to minimize new RA procurement (beyond the amounts already purchased under multi-year contracts), as well as transparency and minimization of ISO back-stop need. It is expected that the LSEs will make year ahead showings with QF contracts first, then units under long-term contracts and maybe some other resources picked up in the current year RFO. Example: Resource A Pmax 200 MW at 50% effectiveness factor, resource B Pmax 100 MW at 20% effectiveness factor, resource C Pmax 200 MW at 10% effectiveness factor. Resources B and C are under long-term contract, A is not. If technically ISO needs 50 MW reduction of real MW line flow then under current method the LCR need would be 320 MW or 100*0.2(from B)+200*0.1(from C)+20*0.5 (from A)=50 MW line flow reduction. If ISO does not consider units already under contract the need will be 100 MW all from unit A not under an RA contract. In the latter case the LSEs are led to believe they are long and they do not realize that an additional procurement of 20 MW is required from unit A. Under the current design the LSEs are better informed, leading to more accurate RA procurement.

No	Comment Submitted	CAISO Response
3h	**What Reliability Standards Apply to Non-Bulk Electric System (non-BES) Facilities?** Table 1 in the October, 2017 version of the manual sets forth the NERC performance standards. The NERC reliability standards apply to the BES, which generally means only those facilities operated above 200 kV. The manual does not specify the reliability standards that will be applied to non-BES facilities (e.g., 138 kV and 69 kV) for purposes of establishing LCRs. The manual needs to be expanded to include reliability standards for non-BES facilities.	The current Tariff in section 40.3.1.1 and the LCR study manual mention both NERC performance standards as well as the ISO Reliability Criteria / ISO Planning Standards. As a result currently the reliability standards are the same for all voltage levels regardless of BES definition. See ISO Planning standard #1 in page 4: http://www.caiso.com/Documents/ISOPlanningStandards-November22017.pdf
3i	**There Should be an Interim Release of the Baseline Power Flow Case that the CAISO Intends to Use to Set LCRs.** Based on experience with earlier LCR studies, it would be helpful if the CAISO could release in interim version of the baseline power flow case that the CAISO intends to use to set LCRs. This would be helpful in allowing stakeholders to work with the CAISO to identify any errors or modeling anomalies early in the process.	ISO will post draft base cases by January 15, 2018. All stakeholders are requested to provide comments to these base cases in regards to modeling anomalies. The ISO will incorporate the approved CEC forecast during the comment period and will repost the cases with the updated forecast and the stakeholder comments that are received. There will not be a second comment period, however, the updated base cases will be made available to stakeholders.

No	Comment Submitted	CAISO Response
4	**Center for Energy Efficiency and Renewable Technologies (CEERT)** **Submitted by: Liz Anthony**	
4a	**Provide energy need component for efficient procurement of use limited resources.** The Center for Energy Efficiency and Renewable Technologies (CEERT) appreciates the opportunity to comment on the California Independent System Operator (CAISO) 2019 Local Capacity Area Technical Study Draft. As we begin a long transition away from relying almost exclusively upon natural gas for Local Capacity Requirement (LCR) procurement, there is a need to provide more information in the LCR Study process to allow for efficient procurement of use limited resources especially preferred resources such as hybrid storage/demand response and local solar. CEERT does not believe there must be significant change to the study process itself, but simply providing one number – the 1-in-10 peak load for the defined LCR area is no longer sufficient to guide procurement.	The changes proposed herein are significant to both the study process and to the Resource Adequacy program. Providing required energy needs per area and sub-area requires significant amount of time and resources which would significantly extend the study period and compromise the CPUC's desired schedule. The current RA program is a pure capacity accounting mechanism at the local and system level, in order to implement energy needs requirements the RA program would need to be changed or capacity counting needs to be adjusted. This issue should be contemplated during any RA re-design effort. Further, market changes may be required to allow for a "reservation" of local resources use since the current market design allows for such resources to be depleted for system or economic needs well before a local need arises.
4b	**Mitigating voltage collapse prior to adding local generation.** First, where the study process demonstrates that voltage collapse is the consequence of the limiting transmission contingency, the MVAR of reactive power required to provide sufficient reactive margin following the contingency needs to be disclosed. In addition, the underlying thermal import limit that would now determine the LCR requirement must be provided. Because the reliability protocols are somewhat less restrictive once the threat of a cascading outage following voltage collapse is mitigated (N-1-1 load shedding is allowed), and post contingency redispatch of quick start reserves is now possible, this information provides the ability to judge the advantage of mitigating voltage collapse prior to adding local generation.	See response to question 2c above. Note that while load shedding is allowed under N-1-1 contingency in non-high density urban load areas, the ISO Grid Planning Standards do not allow load shedding for overlapping N-1-1 contingencies for high density urban load areas (http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf).
4c	**Provide energy need component for efficient procurement of use limited resources.** Second, because use limited resources will become a more significant source of LCR mitigation, the procurement metric needs to shift to consider the on peak	See response to question 4a above.

No	Comment Submitted	CAISO Response
	energy requirement as well as the absolute peak capacity need. The procurement requirement is now the quantity of on peak energy defined as the area under the curve formed by the 1 in 10 peak load shape and the transmission import limit. Because this on peak energy will be met with a portfolio of resources that depend on combinations of technologies to provide LCR mitigation, the net qualifying capacity of the individual resource is no longer sufficient to define value in mitigating the LCR need. For example, because storage in combination with demand response and/or solar PV will be widely available, the procurement needs to consider how that storage can be recharged during relatively high load hours rather than simply adding to the duration of battery storage.	
4d	**Load forecast and peak-shift** Third, at this point, it is not clear whether the California Energy Commission (CEC) load forecast used in this year's study will continue to rely on scaling of historic load shapes and thus require use of an exogenous "peak shift factor" to account for the impact of incremental behind the meter solar. The CEC is transitioning its forecasting methodology to explicitly deal with this issue in its base case forecast, but it may not complete this transition in time to be used in this year's study process. If the CAISO continues recent practice of adding a "peak shift factor" to the CEC forecast, that factor must be added to the hour that the peak load is being shifted into, not the historic peak hour. In addition, the on peak energy produced by the incremental solar that causes the peak shift must be subtracted from the on peak energy requirement that is reported.	For the 2019 LCR studies, the ISO intends to use the CEC load forecast provided in 8760 hours format. The ISO intends to work with the CEC and CPUC such that the load forecast data provided include any coincidence adjustment if warranted including peak-shift. Please follow the CEC open stakeholder process for actual implementation.

No	Comment Submitted	CAISO Response
5	**Sierra Club, Earthjustice** **Submitted by: Matthew Vespa**	
5a	**CAISO revaluate 1-in-10 demand in the Moorpark area given sizable discrepancies in observed load and 1-in-10 projections.** CAISO's LCR assumption uses the CEC mid-case/low AAEE 1-in-10 peak load forecast for local capacity areas. CAISO's August 16, 2017 Moorpark Sub-Area Local Capacity Alternative Study forecast Moorpark area 1-in-10 demand at 1,723 MW.[1] The CEC does not provide a forecast for the Moorpark subarea. Instead, because Moorpark is a subset of the Big Creek/Ventura area included in the CEC forecast, CAISO relied on SCE's load forecast allocation methodology to derive Moorpark peak load.[2] However, actual load data suggests the Moorpark 1-in-10 forecast is significantly overstated. As shown in the attached load data, the highest Moorpark area load during the record breaking heatwave over the Labor Day weekend was 1,596 MW, 127 MW less than the 1-in-10 forecast assumed in the CAISO study. While the CAISO forecast is for 2022, given that the CEC Big Creek/Ventura mid-case/low AAEE forecast projects slightly declining peak load, one would expect 1-in-10 demand in 2022 to be similar or slightly lower than 1-in-10 demand today. Because SCE will soon be issuing an RFO to meet Moorpark area need, an accurate understanding of 1-in-10 demand is critical to ensuring the appropriate level of procurement. Accordingly, Sierra Club requests CAISO investigate the discrepancy between 1-in-10 peak demand assumptions for the Moorpark subarea and actual load data and make any necessary modifications to its determination of LCR need.	This matter will be examined as the ISO and SCE revisits Moorpark procurement.
5b	**Local area need distinguish between voltage and generation need.** Second, CAISO has historically expressed local area need in terms of MW of generation. Yet the Moorpark Sub-Area Study underscores the distinction in voltage and generation needs where voltage collapse is the identified reliability	The LCR reports clearly distinguish between thermal overload and voltage support (collapse) or dynamic instability situations. Further, the local capacity technical studies focus on year ahead requirements

[1] CAISO, Moorpark Sub-Area Local Capacity Alternative Study (Aug. 16, 2017) p. 5, https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.
[2] Id. p. 10.

No	Comment Submitted	CAISO Response
	concern. Thus, in the Moorpark Sub-Area Study, generation need was substantially reduced with the provision of voltage support. In addition to continuing to distinguish between voltage and generation needs in the Moorpark area, CAISO's local area studies should include more transparent information on voltage and generation need in all of its local area studies. This added granularity will allow non-fossil resources capable of providing voltage support services to potentially meet local area need and reduce unneeded reliance on fossil-fueled generation.	where it is not practical for new voltage support devices to be planned and implemented, and voltage support reinforcements that are already moving forward are taken into account. New alternatives can be explored in the transmission planning process. Please also see response to question 2c above.
5c	**Any additional investment in voltage support to meet Moorpark area need be included in CAISO's transmission planning process.** Finally, given that voltage support substantially reduces local area need in the Moorpark area, as part of its Transmission Plan, CAISO should identify potential transmission upgrades, such as a synchronous condenser, to provide the requisite level of voltage support. Sierra Club intends to make this request in the Transmission Plan process but also raises the issue here given its relationship to meeting local area need in the Moorpark subarea.	See response to questions 5b and 2c above.