The ISO received comments on the topics discussed at the March 9, 2017 stakeholder meeting from the following:

1. California Public Utilities Commission (CPUC) Staff
2. Pacific Gas & Electric (PG&E)
3. San Diego Gas & Electric (SDG&E)

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: Michelle Kito**	
1a	**CAISO Should Make its "Final" Power Flow Studies Available to CPUC Energy Division Staff** CPUC Energy Division staff has requested the "final" power flow studies from CAISO and will continue to work with CAISO to obtain access to this data before the RA decision is issued this year.	The ISO and CPUC legal staff are working on non-disclosure agreements to enable the sharing of this information with CPUC staff.
1b	**CAISO Should Consider Revising its Schedule** In its presentation, CAISO indicates that the, "CPUC and the ISO have determined the overall timeline," and indicate that the date for the "Final 2018 LCR report" would be May 1, 2017. As Energy Staff have indicated previously (see November 14, 2016 comments on the CAISO's study assumptions), in its Decision (D.) 16-06-045, the CPUC found that ¨[i]n order to promote due process to all parties," that among other provisions, ¨[t]he final studies should be filed and served in the then-current RA proceeding by April 15 of each year, unless otherwise scheduled by the ALJ or scoping memo¨ (p. 60). The Scoping Ruling in the Commission proceeding, R.14-10-010, currently calls for the final studies to be submitted on April 15. In response to Energy Division staff's previous comments, CAISO responded that: The ISO will seek to expedite its process as much as possible. Timing is bounded in part by availability of CEC load forecast, actual running the studies and allowing two rounds of stakeholder meetings/calls to present the results and comment periods. The ISO Reliability Requirements BPM (page 185) is very specific about the LCR study timeline. The publication of the Final Study Report is to be done targeting the first week in May and no later than end of June. https://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/Reliability%20Requirements%20BPM%20Version%2030_clean.docx	The ISO notes that the resource adequacy process was originally established in 2005-06 timeframe. At that time a common process timeline was established between the ISO, CEC and CPUC on a common process timeline, which the ISO enshrined – in varying degrees of detail – in the ISO's tariff and relevant business practice manual. (See Reliability Requirements BPM (page 185). The ISO's target date for completion of its studies has generally been a full month in advance of the latest date required in that schedule. The ISO is open to revisiting the discussion, and recognizes that other state agencies will need to be involved as the ISO relies on inputs from others in order to complete its studies.

	Energy Division staff encourages CAISO to reconsider its timeline in light of the Commission's request. A May 1, 2017 date for releasing the final report will impact the CPUC's ability to review the study in time for the 2018 Resource Adequacy requirements for the LSEs we regulate.	
1c	**CAISO Should Explain why it is Using the Peak Shift Adjustments in Southern California, but not in Northern California** In the Summary of Findings, CAISO staff indicated that, "Draft LCR results herein use CEC forecast with peak shift for all southern LCR areas and non-peak shift for all northern LCR areas" (p. 4). It would be helpful to understand CAISO's reasoning for using different load assumption in Southern California than what it uses in Northern California. In addition, it would be helpful if CAISO could explain whether it changes other assumptions when taking into consideration the peak shift adjustment (e.g., later hour, different import assumptions, etc.).	The ISO appreciates the comment and agrees the incorporation of the peak shift is important in planning. The ISO is in the process of incorporating this into the analysis and base case development. There are some differences within the models and system topology of the ISO controlled grid between the northern and southern systems, resulting in a different pace of implementation. For southern California, the ISO has observed that peak load is trending toward later timeframe (5 p.m. to 6 p.m.) which necessitates the use of peak shift estimate provided by the CEC. The CEC, in its analysis of peak shift impacts of using hourly BTM PV production profiles and hourly AAEE system impacts, also indicated this trend for southern California. The ISO received this analysis from the CEC as part of the study assumptions used for the Encina OTC deferral study. Addressing the PG&E area requires considerably more effort and is anticipated to have a much lower impact at least in early years, so it is being phased in. The ISO controlled grid for the PG&E system is modeled to the transmission to distribution (T-D) voltage interface with the BTM-PV connected to the distribution system in the local areas. There are over 1700 discrete loads in the PG&E area model. The CEC forecast adopted in January 2017 includes PV Peak Shift and for the PG&E TAC area is 273 MW in 2018 and 818 MW in 2022 with the Peak Shift to be spread across the high number of T-D load buses of the PG&E area. The ISO is working with PG&E in the 2017-2018 transmission planning process to incorporate the base case and reliability assessment as a sensitivity study indicated in the ISO 2017-2018 transmission planning process draft study plan. The location of the BTM-PV mapping to the T-D load buses is critical in determining the local area constraints and the ISO is continuing to work with PG&E on

		the modeling of the BTM-PV within the 2017-2018 transmission planning bases cases. The CEC Peak Shift in 2018 when spread across PG&E T-D load buses will have a minimal impact on the LCR. The ISO recognizes that in 2022 this will have a larger impact. The 2017-2018 transmission planning process sensitivity study will also provide some information with respect to the longer term impacts of the Peak Shift on the local capacity areas in the PG&E system. The ISO will be incorporating the updated modeling of the BTM-PV at the load buses and Peak Shift into the 2019 and 2023 local capacity technical studies models.
1d	**CAISO Should, as a Sensitivity, Determine the Lowest LCR Need for the San Diego Sub-Area** For LCR purposes, CAISO examines the LA Basin and the San Diego sub-area combined and chooses the most effective resources to meet the LCR requirements, by TAC area. It is Energy Division staff's understanding that resources are selected in the San Diego sub-area because these resources are considered more effective. Nonetheless, Energy Division staff request that CAISO run a case minimizing the need in the San Diego sub-area. This serves two purposes: 1) it would provide parties with information on how much more or less effective resources are in the San Diego versus the LA Basin, and 2) it represents a different allocation of local resource responsibility and cost and could be more reflective of the reliability benefits received by the customers in the two areas, considering that San Diego's load is considerably less than the requirement in many months of the year and that many of SONGS-related expenses (e.g., RMR of Huntington Beach) are shared across the two TAC areas.	The process used to develop the requirements for the San Diego sub-area and the LA Basin area are described in more detail in the draft report issued on April 6. The San Diego resources are more effective in mitigating overloads in the San Diego area (or at its boundary), whereas the LA Basin resources are more effective in mitigating overloads in the LA Basin area (or at its boundary). These two objective functions (no overload in either area) must be simultaneously met in order for the system to be in a safe operation zone. In addition, one of the foundational principles of the LCR study is to achieve the minimum generation requirement by dispatching the most effective available resources to mitigate identified reliability concerns. This principle has generally been agreed upon by the CPUC and the stakeholders since the inception of the RMR/LCR process to minimize overall LCR requirements and provide correct economic signals regarding potential transmission reinforcement. The ISO studies follow the 2018 LCR manual as discussed at the October 31, 2016 meeting. The ISO considers its study results to correctly reflect the LCR assumptions, methodology and criteria and represents the minimum LCR requirement. Regarding the requested sensitivity, the ISO is hesitant to study increasing the volume of less effective generation in one area to reduce

		the requirement for more effective resources in another, and also considers that such a scenario would lead to scenarios in the other direction – studies of increasing San Diego requirements to reduce LA Basin needs. As these scenarios involve optimizing around a different objective function, they are beyond the scope of simple sensitivities, and also accordingly require additional time to conduct. They also shift away from the fundamental principle of minimizing local capacity needs. The ISO will look for further comment and discussion on this issue.
1e	CAISO Should Explain Why the Local Area Needs have Increased in the San Diego Area The local need in the San Diego/Imperial Valley (IV) area increases by a considerable amount in 2018 over previous years. The table below shows the historical local capacity need, as well as results from the draft 2018 and mid- and long-term studies. While this may be the result of moving the need from the LA Basin to San Diego, this should be thoroughly explained. The large increase in the San Diego local requirement is concerning given the trends in load forecasts and the significant transmission investments that have been made in the Southern California area generally and the San Diego area in particular. In addition, Energy Division staff look forward to working with the CAISO to consider combining these two areas and providing effectiveness factors, rather than drawing a bright line between the need in LA and San Diego.	The increase in the LCR need for the overall combined San Diego-Imperial Valley LCR in 2017 – considering the corrected value of 4635 MW presented in the draft 2018 Local Capacity Technical Study can be attributed to two factors in particular: - The cancellation of the IID-planned transmission upgrade projects between IID and SDG&E. In 2016, planned 230 kV transmission upgrades between IID and Imperial Valley Substation were modeled, mitigating the loading concerns on the El Centro – Imperial Valley 230 kV ("S") line under contingency conditions.). The ISO also notes that for the 2015 LCR results, the San Diego-Imperial Valley area also had high requirements (3910/4112 MW) primarily due to the S-line transmission constraint when no transmission upgrade between IID-SDG&E was modeled. - The consideration of restriction on Aliso Canyon gas storage output that was partially mitigated in the 2017 local capacity analysis. The 2018 local capacity requirements for this area demonstrate a reduction from the corrected 2017 results for the combined San Diego-Imperial Valley area resulting largely from eliminating any mitigation for gas storage impacts due to the benefits of the enhanced gas balancing rules. It should be noted that no mitigation has been included in draft 2018 results to date to account for possible gas storage restrictions resulting from changes to relying on tubing versus casings for gas withdrawal from storage facilities in the affected area.

		While the ISO would also appreciate the opportunity to simplify the analysis of this complex area, we note that there are contingencies that can be at times binding on the LA Basin area, contingencies that can be binding on the San Diego sub-area, contingencies that can be binding on the combined LA Basin area-San Diego sub-area, and contingencies that can be binding on the San Diego-Imperial Valley area, all of which need to be respected. As such, simply combining the LA Basin and San Diego sub area into a single area for procurement sharing does not seem practical. It is important to note that the "effectiveness" of resources to address a reliability concern is an output of a power flow analysis rather than an input and varies depending on the system configuration being modeled and the contingency and limitations being studied. It is also not clear how that would address the tariff need to delineate local capacity needs by TAC area.

No	Comment Submitted	CAISO Response
2	**Pacific Gas & Eclectic (PG&E)** **Submitted by: Ronnie Lau**	
2a	**General** At the March 9 stakeholder meeting, PG&E learned that the CAISO has incorporated peak shift into its local capacity technical studies for some or all of the southern areas in the CAISO footprint. PG&E requests the CAISO to confirm whether in future studies it will examine the peak shift effect and document its findings for each of the PG&E's local areas, as well.	Please refer to the response to CPUC comment 1c.
2b	**North Coast/North Bay – Lakeville Sub-area** For the 2022 LCR need, the CAISO reported thermal overload on the Moraga-Sobrante 115 kV line following the Vaca Dixon-Tulucay and Vaca Dixon-Lakeville 230 kV lines outage (See North Coast/North Bay Area Presentation - Slide No. 11). In the past, the Eagle Rock-Cortina 115 kV line located in the North Coast area had been identified as the overloaded equipment. It is not clear how the equipment overload migrated to the Bay Area. PG&E recommends the CAISO reviews its findings and lists out the assumed Pittsburg area generation for added information. The Vaca Dixon-Lakeville 230 kV Reconductoring Project has now been officially cancelled by the CAISO.1 PG&E is working to seek higher wind-speed emergency ratings for the line, future LCR needs for this sub-area should take into account the new line ratings.	This contingency can result in overload of both the Eagle Rock-Cortina and the Moraga-Sobrante 115 kV lines. Both constraints must be simultaneously met. The Moraga-Sobrante 115 kV constraint has been more relevant in latest studies due to elimination of need in the Oakland-Pittsburg sub-area and consequent retirement of the Pittsburg power plant. The LCR base case development occurred during December 2016 and projects are modeled with their status available at that time. The cancelation of Vaca Dixon-Lakeville 230 kV Reconductoring Project was included in the ISO 2016-2017 Transmission Plan that was approved by the ISO Board of Governors on March 15, 2017. The in-service date for this project prior to the cancelation, per PG&E latest information, was October 2020 and as such does not impact the 2018 the LCR assessment. The ISO will incorporate cancelation of the project in next year's long-term LCR studies and will update the ratings in the base cases after PG&E updates the Transmission Registry with the new ratings.

2c	**Greater Bay Area** The Tesla-Newark 230 kV Path Upgrade Project was included in the 2018 and 2022 study cases (See Greater Bay Area Presentation – Slide No. 4). This project is also cancelled2 and it should be removed from the study assumptions. The Morgan Hill Area Reinforcement Project (Spring Substation) was assumed to be in-service by 2022. However, this project is on the list of projects that the CAISO has placed on Hold. PG&E has been asked not to proceed with permit filings until the CAISO completes its review.[3] The Evergreen-Mabury 60 kV to 115 kV Conversion Project was modeled in the 2022 Greater Bay Area study case. The project should be listed on Slide No. 4 of the presentation. With the change in status for the various projects in the PG&E service territory, it is essential to document which projects are included or excluded or have no impact on the LCR study results. PG&E understands the CAISO has taken the LCR needs into consideration before a project should be cancelled or not. However, for any areas where the cancelled projects have not been taken into account, the LCR needs should be re-determined. Adding clarity and consistency is particularly important to the 2018 LCR need determination.	As a part of the review of previous projects the ISO relied on the 2017 LCR assessment to confirm that there were no impacts prior to recommending that the project be cancelled. In addition, the project was included in the base cases as the in-service date for the Tesla-Newark 230 kV Path Upgrade Project prior to cancelation was March 2019, per PG&E's latest information. Therefore the cancelation of the Tesla-Newark 230 kV Path Upgrade Project does not results in an increase or otherwise change in the 2018 LCR requirements for the Bay Area. The LCR base case development occurred during December 2016 and projects are modeled with their status available at that time. The change in status to put the identified projects on hold of was included in the ISO 2016-2017 Transmission Plan that was approved by the ISO Board of Governors on March 15, 2017. The in-service date for these project prior to the cancelation, per PG&E latest information, was May 2021 for the Morgan Hill Area Reinforcement Project and June 2021 for the Evergreen-Mabury 60 kV to 115 kV Conversion Project and as such does not impact the 2018 LCR assessment. . The ISO will incorporate the appropriate updated status for these projects in next year's long-term LCR studies. As part of the review of the previously approved projects that were cancelled an assessment of the 2017 LCR results was reviewed. The ISO will continue the assessment of the projects on hold in the 2017-2018 transmission planning process.

No	Comment Submitted	CAISO Response
3	**San Diego Gas & Eclectic (SDG&E)** **Submitted by: Nuo Tang**	
3a	**Process Improvements:** SDG&E recognizes that these comments are being submitted after the March 23, 2017 due date. At least in part, the lateness of the comments owes to the current process used by the CAISO to allow stakeholders to investigate the details of the CAISO's analysis. Because the CAISO asserts its "final" LCR power flow case contains commercially sensitive information, stakeholders such as SDG&E are forced to perform their own analysis using a "starting point" LCR power flow case that is posted on the CAISO website. SDG&E's initial efforts produced results strikingly different than the CAISO's. With the much-appreciated cooperation of the CAISO staff, SDG&E quickly learned that data in the "starting point" LCR power flow case posted by the CAISO differed in important ways from data in the "final" power flow case. However, determining whether the difference between SDG&E's and the CAISO's results was due to the differences in data contained in the cases, or to differences in modeling approach, was not obvious and required considerable back-and-forth with the CAISO staff. In the end, there were significant differences in both data and modeling approach. SDG&E believes the LCR stakeholder process would be enhanced if there were some way for the CAISO to post an "intermediate" LCR case early in the process. An "intermediate" LCR case would give stakeholders the benefit of the CAISO's own vetting process and help to narrow differences in results that arise as a result of different data. While it is too late in the current process to incorporate this suggestion, it is not too late to think about whether an "intermediate" case could be posted for the 2019 RA compliance year process.	The ISO appreciates the concern regarding very tight timelines to conduct the analysis, receive and respond to comments, and move to finalizing results. For clarity, the LCR process envisions that the ISO and stakeholders can run LCR studies based on the published base cases and by following the LCR manual – and producing similar results. This year's process did not meet that expectation both due to the schedule the load forecast was received by as well as modeling changes that were necessitated in the San Diego area. The overall schedule for the ISO's LCR process contemplated receiving the CEC load forecast by December 30. This year, the forecast was not approved by the CEC until late January, after the LCR base cases were posted, and further updates to the San Diego load forecast were made in March. Further, the base cases provided by the utilities did not adhere to the LCR manual requirements, by including transmission projects and generation resources not anticipated to be in service by June 1, 2018 and resources anticipated to be offline were removed completely from the base cases rather than being placed out of service. These issues necessitated further changes by the ISO. We appreciate that these changes would be challenging for stakeholders to model and will be working with the utilities to ensure that future cases better meet expectations given the very tight timeframes for developing, reviewing and finalizing results. Nonetheless, the ISO is also open to working with the state agencies and the participating transmission owners to consider the overall schedule and potential process improvements.

3b	**Use of Thirty-Minute versus Four-Hour Emergency Ratings** NERC reliability standards permit reliance on emergency ratings for some period of time following an initial transmission contingency. The CAISO assumes the extreme contingency condition -- upon which LCRs are determined -- will last four hours. The CAISO takes the position that unless there is contractual certainty that undispatched generation will be available throughout the full four hour period that is effective in mitigating flows on limiting transmission elements, anything less than a four-hour emergency rating cannot be relied on; i.e., normal ratings must be used. SDG&E believes the CAISO and stakeholders should consider whether the current policy is overly conservative. In an LCR analysis, the objective is to maximize imports into the LCR area. That often means that there will be considerable existing dispatchable generation within the LCR area that is operating below its Net Qualifying Capacity (NQC) level. For example, SDG&E's "final" power flow case had 247 MW of headroom available on dispatchable generators within the Greater Imperial Valley-San Diego area. While it is impossible to know in advance how much of this headroom might be subject to a contractual commitment, it seems reasonable to assume that during a one-in-ten heat storm, most existing generation will have a strong economic incentive to be available and to quickly respond (within thirty minutes) to CAISO dispatch signals in the event of critical transmission contingencies. Of course, generation varies in its effectiveness for mitigating high flows on different facilities. Additionally, there must be effective dispatchable generation on both sides of the constraint. So the decision as to whether a thirty minute emergency rating can be relied on will depend on the specific circumstances of the LCR power flow case. SDG&E notes that while the extreme condition (e.g., loss of a generator, one-year-in-ten heat wave) may be assumed to last four hours, that does not automatically mean that any emergency ratings relied on also have to be valid for that same four hour period. Instead, the question should be whether it is reasonable to assume that for any thirty minute interval within those four hours, dispatchable generation will be available to redispatch sufficient to bring flows back to within normal ratings.	LCR studies do allow for the use of short-term ratings as long as an approved operating procedure exists - or is proposed - to transfer load to other system. One does not exist in this area. Similar to conventional and non-conventional resources that qualify for meeting local RA needs, the requirement for hour-hour availability extends to transmission resources as well. The intent of the resource adequacy (RA) program is to provide resources "when needed and where needed" in order to reliably serve the load, therefore if any resources must be available to unload circuits post single events (or G-1) followed by a single event, the need must be specified and resources must be under RA contract. Immediately after the contingency or 30 minutes after a contingency occurs, to avoid firm load curtailment, any resources used during the readjustment period must be included in the LCR need. In addition, the contracted resources must be able to be dispatched and be available within a 30-minute timeframe. Some generators with steam boilers would need more than 30-minute timeframe to start generating and provide output to the grid. Uncontracted resources may not be available, as well as not being obligated to provide capacity when need arises. Allowing for uncontracted or otherwise energy only resources to be used to avoid firm load drop during single contingency events is contrary to the purpose of the RA program. These uncontracted resources, or energy only, resources are not obligated to run to provide needed capacity for local reliability purposes. Please see previous paragraph.

	In SDG&E's "final" power flow case, SDG&E found that following the loss of the 500 kV North Gila-Imperial Valley line, it was possible to increase the output of unloaded dispatchable generators within the Greater Imperial Valley-San Diego area by 168 MW, and decrease the output of generators east of North Gila, with the result that flows on IID's S-line dropped from the emergency rating of 407 MVA to the normal rating of 370 MVA. This is evidence that it should be possible to rely on the emergency rating of S-line. SDG&E estimates that if the emergency rating of the S-line can be relied on for purposes of determining LCRs, LCRs will be reduced by 168 MW compared to relying only on the normal rating of the S-line. Our analysis shows that for G-1 contingency the S-Line is pre-loaded to almost 37 MVA (93 Amps) and it takes 30 minutes for G-1/N-1flow to increase the conductor temperature to that allowed for continuous rating (not even the emergency rating!). Thus during this time, if CAISO could replace 168 MW of IV generation by the same amount of import to the SDG&E's load area (or use the available headroom of the available generators in the SDG&E basin), then the SDG&E's LCR could also be decreased by almost 168 MW.	The ISO does not have authority to curtail resources in a different control area due to single contingency events within its jurisdiction. Please see above paragraph for inclusion in the LCR need of all resources required to be dispatched in order to avoid loss of firm load for any single contingency, or overlapping contingency in high density areas.
3c	**Consistency in Time-of-Day Assumptions is Needed** The CAISO's existing LCR methodology generally requires that the modeling is performed assuming imports into the CAISO balancing authority are equal to established Maximum Import Capability (MIC) amounts. MIC amounts are set based on import flows that occurred during historical peak load hours. Historically, peak load hours have been in the 2:00 pm to 6:00 pm PST timeframe. In the CAISO's LCR analysis for the 2018 RA compliance year, a peak "load-shift" adjustment is applied to the CEC's forecast peak loads to account for the effect of increasing behind-the-load meter rooftop solar. The rooftop solar has the effect of depressing peak loads in the 2:00 pm to 5:00 pm timeframe, with the result that a new peak-load is emerging in the 6:00 pm – 7:00 pm timeframe. The result of the peak load-shift adjustment is to create inconsistency between the MIC assumptions used in the modeling and the peak loads used in the modeling. SDG&E recommends that cases based on the upcoming WECC anchor data sets with Pmax set to NQCs be utilized in future LCR studies.	The MIC is recalculated every year based on a rolling two year data. Therefore the MIC calculation already accounts for 6:00 PM hour or later. MIC is in fact the Maximum Import Capability when load is above 90% of the absolute peak. Hours 6:00 PM or beyond on a hot summer day are already included in the calculation since load is >90% of absolute peak. The ISO believes it is even more important to maintain the MIC on a going forward basis, especially after solar sunset due to unavailability of this type of resource and the need to rely on imports to serve load (especially after all internal, local, non-solar resources are accounted for.) LSEs must be allowed, to rely upon the same level of MIC after solar sunset in order to assure delivery of resources needed for resource adequacy.

	A related issue involves the assumed dispatch level of certain generators that have a material impact on the determination of LCRs for the Greater Imperial Valley-San Diego area and for the LA Basin area. The CAISO's modeling assumes certain gas turbines in the Yuma area are operating at full output. SDG&E understands the CAISO makes this assumption based on the expectation that if California is in a one-in-ten peak load condition, then Arizona is likely to be in a similar condition. However, as noted above, the peak load-shift adjustment is meant to recognize that the highest CAISO balancing authority area loads will be occurring in the 6:00 pm to 7:00 pm timeframe; which may be well after the time when Arizona would find it necessary to run gas turbines in the Yuma area. It may therefore be inconsistent to model the Arizona gas turbines at full output in an LCR case where a peak load-shift adjustment is being used. The CAISO's modeling assumes the La Rosita-U1 (IV-GEN2-U1) gas turbine new Mexicali – which can be physically switched between the CAISO and CENACE balancing authorities – is off-line. This modeling is inconsistent with how the CAISO is treating the Yuma area gas-turbines. To say it the other way around, the CAISO's modeling of the Yuma area gas-turbines is inconsistent with how it is modeling the La Rosita-U1 (IV-GEN2-U1) gas turbine new Mexicali. The La Rosita-U1 (IV-GEN2-U1) gas turbine modeling is important because it is effective in mitigating S-line flows under contingency conditions.	ISO does not have authority to curtail resources that are needed for RA in a different control area in real time (before any contingency) or due to single contingency events within its jurisdiction. Every summer in past years this resource is exclusively serving CFE loads and it is connected to their system during summer operation, therefore being unavailable for ISO to operate or for other LSEs to procure. If forced to connect to the ISO grid rather than CFE this resource will only create a circular need since CFE will now import the same amount from IV or San Diego area effectively increasing the need by about the same amount.
3d	**The Output of YCA Cogeneration Unit in the Yuma Area is Directed by SDG&E. YCA Should be Assumed Off-Line During Critical Contingency Conditions.** Because SDG&E has contractual rights to control when YCA operates, LCR modeling should assume that the plant is off-line during the extreme conditions assumed for purposes of determining LCRs. Specifically, if the TDM combined cycle plant is off-line during a one-in-ten heat wave, SDG&E would ensure that the YCA plant is not operating. This will help to reduce S-line flow should there be a subsequent outage of the 500 kV North Gila-Imperial Valley line.	Please provide proof of contractual rights. If contractual rights are available an operating procedure needs to be established to allow access to this resource by ISO real-time operations.
3e	**Stakeholders Need a Clear Understanding of How the Different Dispatch Patterns for Generators in the Greater Imperial Valley-San Diego area and in the LA Basin area, Affect the LCRs Calculated for Each Area**	

	SDG&E's LCR modeling makes clear that dispatching certain generators in the Western LA Basin results in lower Greater Imperial Valley-San Diego area LCRs than dispatching other generators outside the Western LA Basin area. Since no one knows in advance which generators may actually be contracted for purposes of the year 2018 RA compliance showings, it would be helpful if some bookend LCR analysis were conducted to show how the Greater Imperial Valley-San Diego area LCRs, and the LA Basin area LCRs, could vary depending on what generation were actually contracted. It is not clear under which methodology the LCR share of SDG&E is determined, from the LCR requirement for the combined areas of LA basin and SDG&E. The outcome of the current process might be inadvertently shifting some of the LCR costs from SCE to SDG&E. The LCR results provided by the CAISO at the March 9, 2017 stakeholder meeting are based on modeling which assumes, for example, that there is no generation on-line at Alamitos substation in the Western LA Basin. If an alternative assumption were made that generation at Alamitos substation were on-line, SDG&E's LCR analysis suggests that LCRs for the Greater Imperial Valley-San Diego area would be lower. A bookend analysis would be helpful in understanding the cost tradeoffs between those consumers who pay for the costs of meeting LA Basin area LCRs and those consumers who pay for the costs of meeting the Greater Imperial Valley-San Diego area LCRs.	ISO is currently following the LCR methodology as established in 2005-06 time-frame through an open stakeholder process, and gravitates towards achieving overall minimum LCR needs between the combined LA Basin-San Diego-Imperial Valley areas. ISO focuses on identifying minimum LCR requirements before LSE procurement is done. After a procurement portfolio is established ISO can test to see if it meets the reliability needs. ISO concurs that increasing LCR requirements in LA Basin could result in lower San Diego-Imperial Valley LCR need, however this will tend to increase the overall LCR needs for the combined LA Basin-San Diego-Imperial Valley above those already calculated by the ISO. The resources in the LA Basin are much less effective than resources in San Diego and Imperial Valley in mitigating the reliability issue identified for the San Diego-Imperial Valley area.
3f	**LCT Study Should Ensure Most Recent NQC Values are Used** The LCT study seems to be utilizing NQC values for renewable resources that are different than those listed on the 2017 NQC list. The ISO should note and explain in its manual why it chooses to use NQC values that are different than designated.	To the extent possible the ISO is using the latest available NQC. The difference between 2016 and 2017 NQC data is rather minimal and none of them are correct since the 2018 NQC will be used for compliance, and it's only available by August 2017.
3g	**Work with the IID to Find Mutually Beneficial Ways to Mitigate S-Line Loading** It is in all parties' interests to explore different ways of mitigating contingency-based flows on the S-line since the S-line is the binding constraint for the critical contingency condition which establishes LCRs in the Greater Imperial Valley-San Diego area and in the LA Basin area. Several concepts have	ISO is open to suggestions, which should be raised in the ISO's annual transmission planning process. Solutions must be coordinated with IID which is the owner and operator of this line especially if involves any tripping or curtailments in the IID control area.

	emerged which warrant further discussion. For example, a Remedial Action Scheme (RAS) that cross-trips the S-line for the outage of the 500 kV North Gila-Imperial Valley line would eliminate the S-line as a limiting element. Installing a reactive "smart wires" device on the S-line not only would help to reduce S-line flows, but also can be used to push more power through the S-line, if the line is not overloaded.	
3h	**Consider Contractual Mechanisms for Ensuring Key Generators are On-Line During Critical Periods** If there is reason to believe the La Rosita-U1 (IV-GEN2-U1) gas turbine new Mexicali will not be on-line during critical periods in year 2018, it is worth considering whether this unit can be placed under a contract which allows SDG&E to direct the unit's operation during the extreme conditions which determine LCRs. Coupled with an Imperial Valley-La Rosita phase shifter operating policy that provides northbound flow equal to the output of the LRP-U1 gas turbine, the contract could be effective in relieving Even if the generating unit's capacity would not count as RA capacity, the fact that the unit would be running during the extreme condition means LCRs could be reduced.	Any contractual arrangement is advantageous including RA contract. We must also assure and coordinate with CFE to make sure they have other CFE internal resources it can rely upon in order to avoid the circular issue explained at 3c above.
3i	**Implement Phase Shifter Operating Policy that Provides Northbound Flow from La Rosita to Imperial Valley Substation when TDM Trips During 1-in-10 Peak Load Conditions** If a phase shifter operating policy were implemented to provide northbound flows on the 230 kV La Rosita-Imperial Valley line during critical contingency conditions, then the emergency rating of the S-line could be relied on because it would be possible to ensure that flows on the S-line could be reduced from the emergency rating back to the normal rating within 30 minutes of the outage of the 500 kV North Gila-Imperial Valley line. Note that this operating policy would not change Path 45 flow since any northbound flow on the 230 kV La Rosita-Imperial Valley line would be offset by an equivalent southbound flow on the 230 kV Otay Mesa-Tijuana line.	Circulating power from Tijuana to La Rosita through the CFE control system must be coordinated and approved by CFE since it will decrease their capability to serve inland load with costal resources and will also increase losses through their system at the same time. Resources required to fill in this need (at Otay Mesa) are situated in the San Diego sub-area; therefore the savings are dictated by effectively the difference in effectiveness factors between San Diego vs. Imperial Valley connected resources.